Electricity
Asset Management Plan
2010 – 2020

Summary of the Asset Management Plan

Purpose of the Plan

This Asset Management Plan (AMP) has been developed to comply with requirement 7 of the Commerce Commission's Electricity Distribution (Information Disclosure) Requirements 2008 and covers ten years from 1 April 2010 to 31 March 2020. The AMP draws from Vector's internal asset management documents, including detailed policies, strategies and project information.

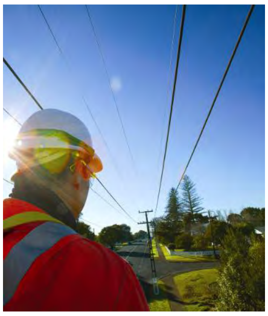
The AMP is consistent with Vector's internal plans and accurately represents asset management practices at Vector as well as the forecasted ten year capital and maintenance expenditure on the Vector electricity network[1]. The objectives of the AMP are to:

- 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 goals;
- Demonstrate innovation and efficiency improvements;
- Provide visibility of best practice asset management at Vector;
- Provide visibility of forecast electricity network investment programmes to external users of the AMP; and
- Meet Vector's regulatory obligations.

Interaction between Objectives and Corporate Goals

Vector's statement of strategic intent reflects our aspiration:

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

[1] After allowing for the difference between Vector's financial year (July to June) and the regulatory financial year (April to March).

From an asset manager perspective the AMP:

- Supports a continued improvement in our asset management performance;
- Is essential to our goal to be world-class asset managers; and
- Will help the Vector Group to achieve its overarching vision.

There is clear alignment between the AMP and Vector's strategic goals. The strategic goals drive Vector's asset management approach, and asset management outcomes support the achievement of these goals.

The Present Investment Environment

The overall investment landscape faced by Vector continues to pose a number of challenges. In many respects these translate into significant potential variability in the level of investment Vector will prudently be able or be required to undertake.

A major economic recession was foreseen at the time of preparing the 2009 AMP, which influenced the capital investment forecasts. In reality the recession has to date had a relatively small impact on electricity demand (as opposed to the impact on electricity volume). Overall the coincident network peak demand increased by 2.1% during 2009/2010 – as opposed to the decline foreseen early in 2009. The implication of this was that projects that were intended to be deferred for one or more years had to be brought back into the short-term planning window, to ensure that security standards can be maintained. The actual customer connection numbers for both residential and commercial sectors were also higher than that forecast for the 2009/2010 financial year.

In spite of the increase in demand and consequential requirement for additional capital expenditure (capex), Vector experienced a flattening in energy volumes during 2009, which drives revenue. Under the current form of price-regulation, Vector has limited ability to address this disconnect. It is essential that Vector has sufficient certainty in the regulatory regime that it will be able to recover its investments before making any commitment to its capital expenditure programme.

For the purposes of this AMP, Vector has assumed that economic growth will resume at relatively modest levels. However, significant global imbalances remain in fiscal and monetary conditions, which may lead to a rapid deterioration in economic growth prospects, with consequential impacts on electricity demands.

Vector's operating environment is also complicated by a number of regulatory and commercial factors.

The regulatory framework is undergoing considerable change. The changes to the regulatory regime are intended to bring greater certainty and therefore improve the environment for investment, but until the regime is fully specified by the Commerce Commission uncertainty will prevail at least during this transition period. Vector's investment and asset management strategies will be dependent on developments in the regulatory regime.

A key element of the regulatory regime is the basis of establishing the value of the regulatory asset base (RAB). While this is one of the input methodologies that the Commerce Commission is currently consulting on, it is concerning that their current preference appears to be for the opening RAB to be determined based on the currently disclosed RAB (i.e. the 2004 Optimised Deprival Valuation (ODV) indexed forward at Consumer Price Index (CPI)). Vector's preferred option is to use a fresh ODV (circa 2010), that would reflect the asset value expected from a workably competitive market, to set the starting RAB for this new regulatory regime. Vector considers that valuing the opening RAB at ODV, which reflects the value of assets that would be employed by a hypothetical efficient new entrant to the market, is the theoretically correct starting RAB value for the new regulatory regime.

The three principle effects of a new ODV are to reflect changes in input prices, over and above CPI, since the last ODV, allow adjustment for any errors in or improvements to the previous ODV and to allow for a reassessment of the optimisation – reflecting critical factors such as the continuing strong growth in demand referred to above.

Valuing the starting RAB using a 2010 ODV would also be consistent with past regulatory decisions as under the previous threshold regime a new ODV was to be undertaken in 2008, but this has not eventuated. The propensity for the Commerce Commission to fundamentally change its approach breaches regulatory best practice and introduces significant uncertainty into the likely future shape of the regime. This regulatory uncertainty has a significant dampening effect on the willingness to invest and, accordingly, may cause Vector to deviate from the investment levels indicated in this plan.

The Commerce Commission has also indicated that it may implement regulatory mechanisms to incentivise quality of supply improvements in future.

Strategies to enhance utilisation of the existing network assets will help to optimise future investments and enhance return on network investments. These strategies include introducing new products and services supported by new technologies to change the demand profiles on existing assets and introduction of smart technologies to enhance the management and control of the network and its asset. Equally, technologies such as renewable energy source for distributed generation could strand network investments. It is important to take a cautious approach and to have strategies in place to ensure network investments are protected.

As part of the Government's accelerated infrastructure package, a number of roading and infrastructure projects have been brought forward. The increased level in roading and infrastructure activities by local and central government agencies also cause a corresponding increase in asset relocation expenditures. In addition, these activities create upward pressure on key input costs, as Vector competes with other significant infrastructure works programmes (for example civil works).

Improvements in the AMP and Asset Management at Vector

Vector noted the results of the Commerce Commission review of the 2009 AMPs, including Vector's. Vector's 2010 AMP has been thoroughly revised to reflect new developments in Vector's approach to asset management and thinking in regard to future proofing for emerging technologies and also takes into account the Commission's feedback on the previous AMP.

Other important changes to the AMP include:

- A review of the network security standards has been completed. The revised standards are now defined in a deterministic language while maintaining their probabilistic intent. The objectives of the review were to re-validate the suitability of the standards (which were developed ten years ago), extend the standards to support the Northern regional network planning, and to make it easier for the users to apply. To support consistent implementation of the security standards, planning tools (including load forecast models, connectivity models, demand at risk and risk exposure models, load flow and fault current models, protection models, etc) are being developed/reviewed;
- Substantial resources have been put to the investigation of emerging consumer and network technologies that could impact materially on the future of the electricity distribution network;

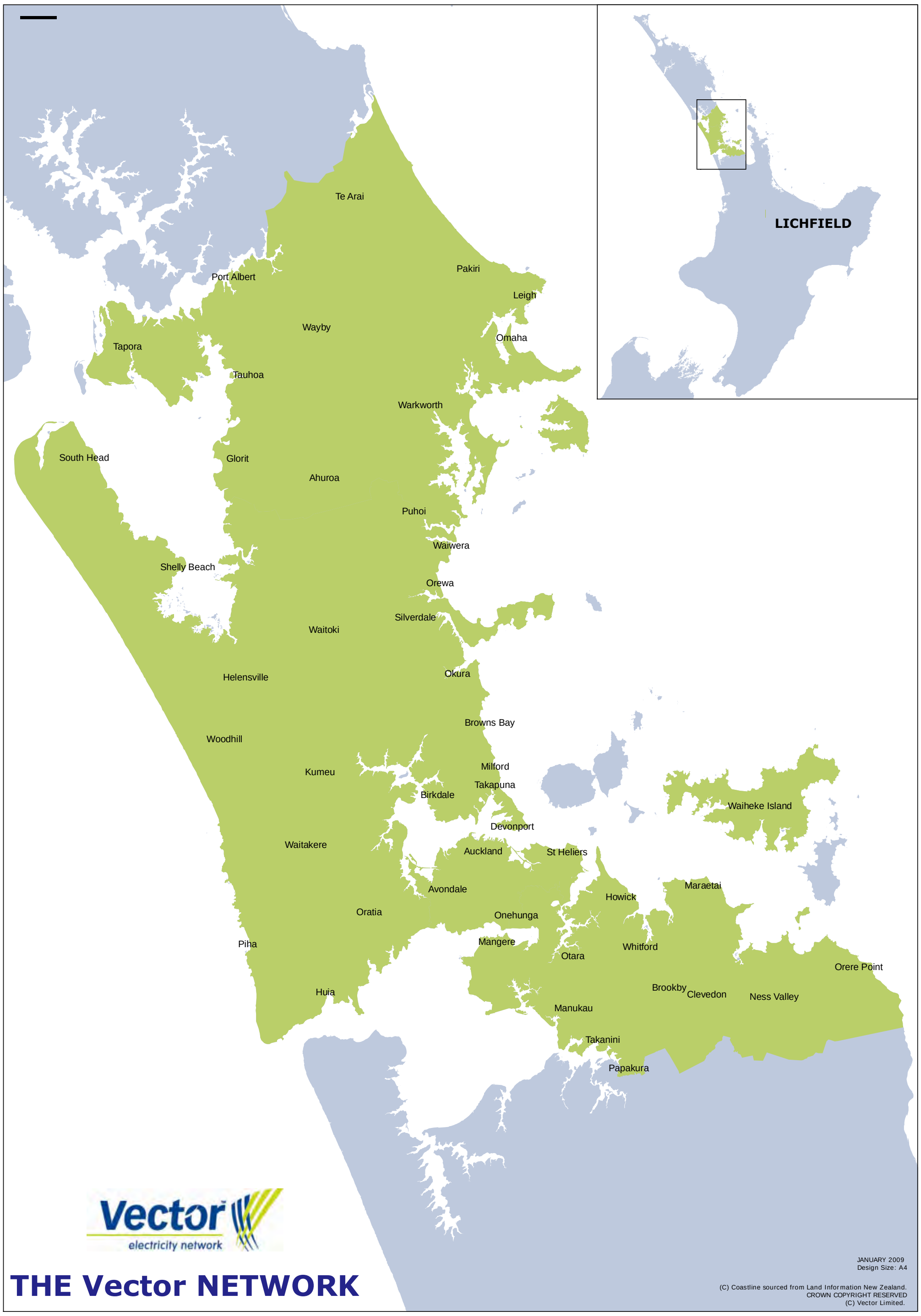
- The network development and asset renewal programmes have been reviewed and are represented in much more detailed in this AMP; and
- Vector has embarked on several asset management related initiatives during 2009, which are reflected in the AMP. These include:
  - Programme for improvement of asset data quality;
  - Improved works coordination within Vector as well as with external parties such as councils and other utilities; and
  - Improving the cyber-security of our SCADA system.

Vector's Network

Vector's supply area covers most of the Auckland region as shown in the map below. Vector operates an electrically contiguous network 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 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 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.



Network Summary (Year ending 31 March 2009)

Description	Quantity
Consumer connections	522,147
Network maximum demand (MW)*	1,711
Energy injected (GWh)*	8,599
Lines and cables (km)**	17,537
Zone substations***	100
Distribution substations	20,828

* Includes embedded generation exports
** Energised circuit length
*** Figure includes Lichfield but excludes Auckland Hospital

Demand Forecasts

Demand growth is a key investment driver for the electricity distribution network. As noted before, despite the recent recession and slow down in housing/building construction, there has been no sign of slowdown in (overall) demand growth since late 2008. The effect of the higher than expected 2009 peak demands has been reflected in the demand forecast contained in this plan.

We have also been monitoring developments of various technologies that could impact on the demand and demand characteristics on the network. Uptake rates of future technologies and technologies new to the network such as heat pumps, electric vehicles, smart appliances and PV panels have been separately identified based on overseas experiences, price trends, manufacturer and supplier technical and commercial developments, local technology substitution, etc. These anticipated uptake rates have been taken into account in the demand forecast, superimposing the impact of new technologies onto the general forecast. Since the uptake rates of these technologies are uncertain, various growth scenarios have been developed.

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

The winter and summer demand forecasts are detailed at zone substation level in Section 5.4. The maximum network demand for 2009 (regulatory year) is given below, as is the energy consumption.

	Peak Demand* (MW)	Total Energy Injected (GWh)
From grid exit points	1,525	8,485
From embedded generation**	186	114
Total	1,711	8,599

* Coincident demand
** Embedded generation includes Southdown

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;
- Customer needs, which vary by customer segment and are reflected by service level standards;
- Striving for least life-cycle cost solutions (optimum asset utilisation) and optimum timing for capex;
- Maximising capex efficiency;
- Outcomes that improve asset utilisation taking 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 practicable;
- Reference to targets set by industry best practice;
- Ensuring assets are operated within their (cyclical) design 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 5.2 of this AMP.

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 (fed 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 4.1 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 operators;
- Ensuring reliable and sustainable network operation;
- 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 perform 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.

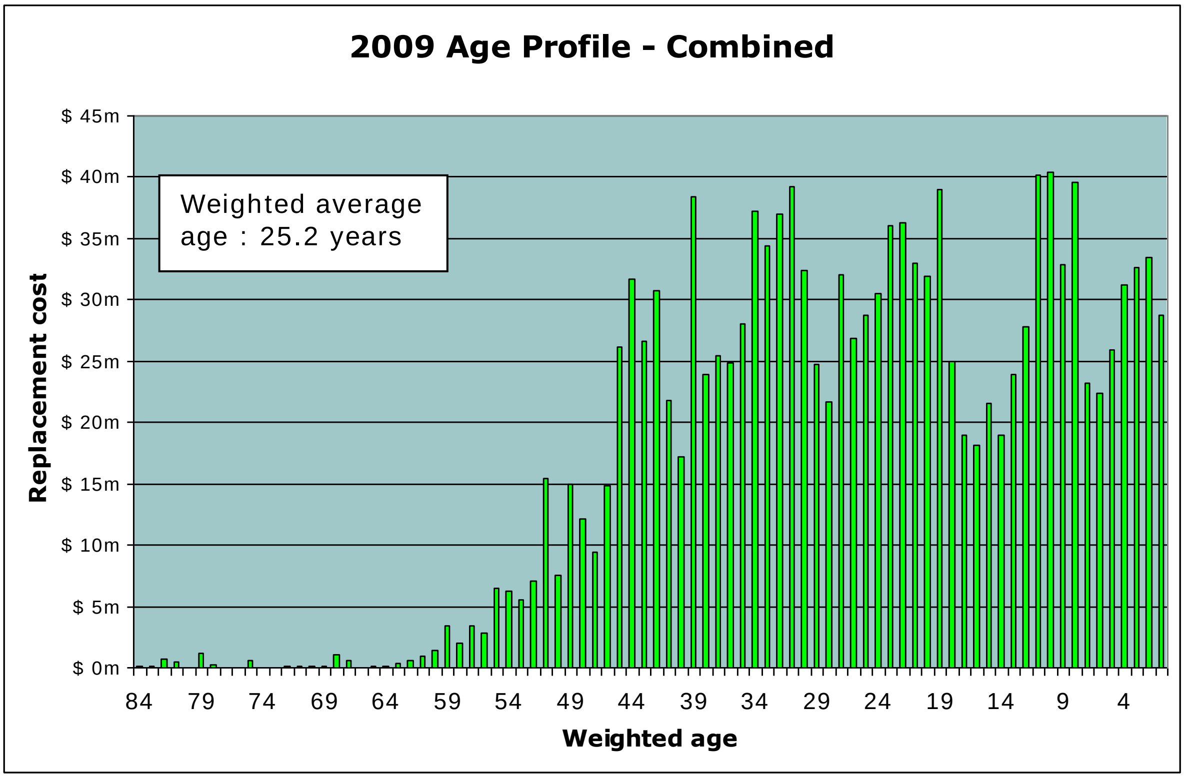
The following summarises the different types of maintenance programmes for the electricity network assets:

- 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.

Age Profile of Assets

The following figure shows the combined age profiles of major assets in Vector's electricity distribution network. The weighted average asset age – 25.2 years – is considered appropriate for a mature, well-functioning electricity distribution network.

Vector's asset replacement and maintenance strategies are not based on asset-age, but in accordance with best-practice, on asset condition. However, the net effect of these strategies is to maintain the average asset age at a relatively constant level.



Risk Management

Risk Management Policies

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.

The consequences and likelihood of failure or non performance, current controls to manage this, 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 5 and Section 6). 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.

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 8.6 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 8.6 of this AMP.

Environment

Vector's environmental policy is contained in Section 8.7 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[2].

Progress against the previous AMP is reported in Section 5.

[2] By contrast, the internal asset management documents are kept up to date on a regular basis.

As noted above, the content of this AMP is consistent with Vector's internal asset management business plans, which are core to the electricity distribution business. Progress in implementing Vector's internal asset management business plans is regularly monitored, and the plans are updated on a regular basis to reflect a changing environment[3].

Vector measures progress against its investment plans and asset performance 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.

[3] Material changes, with potential major budget, risk or reliability consequences, are reported to the Board.

10 Year Forecast of Expenditures	Mar 11	Mar 12	Mar 13	Mar 14	Mar 15	Mar 16	Mar 17	Mar 18	Mar 19	Mar 20
Customer connection	17.5	18.5	19.0	19.7	20.0	19.5	19.2	19.2	18.6	18.5
System growth	43.3	45.3	53.5	62.6	52.8	47.7	40.6	42.4	36.1	40.6
Asset replacement & renewal	47.5	55.4	57.3	56.7	57.7	63.7	66.6	64.1	63.1	63.1
Reliability, safety & environmental	4.5	5.8	5.9	4.3	3.8	3.5	3.2	3.1	3.1	3.1
Asset relocation (including undergrounding)	23.3	22.3	20.1	19.4	19.0	18.8	18.8	18.8	18.8	18.8
Capital Expenditure Subtotal	136.2	147.2	155.8	162.7	153.2	153.1	148.4	147.6	139.7	144.1
Routine & preventive maintenance	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Refurbishment & renewal	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Fault and emergency	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
O & M Subtotal	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4
Total Direct Expenditure	176.6	187.6	196.2	203.1	193.6	193.5	188.8	188.0	180.1	184.5

Content of this AMP

This AMP contains the following sections:

- Summary
- Section 1 : Background and objectives
    - Purpose statement
    - How AMP aligns with Vector's corporate vision and goals
    - Asset management accountabilities and key stakeholders
- Section 2 : Assets covered
    - Distribution area and network configuration
- Section 3 : Future vision
    - Technology roadmap
    - Programmes to prepare for future
    - Long term network strategy
- Section 4 : Service levels
    - Asset and network performance targets
    - Evaluation of performance
- Section 5 : Network development planning
    - Planning criteria and assumptions
    - Investment prioritisation
    - Demand forecasting
    - Non-network solutions
    - Detailed development plans (growth driven)
- Section 6 : Lifecycle asset management
    - Lifecycle planning criteria
    - Maintenance policies and programmes
    - Asset renewal and refurbishment policies
    - Detailed asset renewal and refurbishment programme
- Section 7 : Asset management systems and procedures
    - Asset management process, data and systems
    - Data quality improvement
    - Document management
- Section 8 : Risk management
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    - Capital expenditure plan
    - Operating and maintenance expenditure plan
    - Reconciliation of actual versus planned performance and expenditure

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1. Background and Objectives

1.1 Context for Asset Management at Vector

The concept of asset management and achieving best value from their asset base has always been fundamental to successful infrastructure businesses. Vector's electricity business is no exception to this rule.

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.

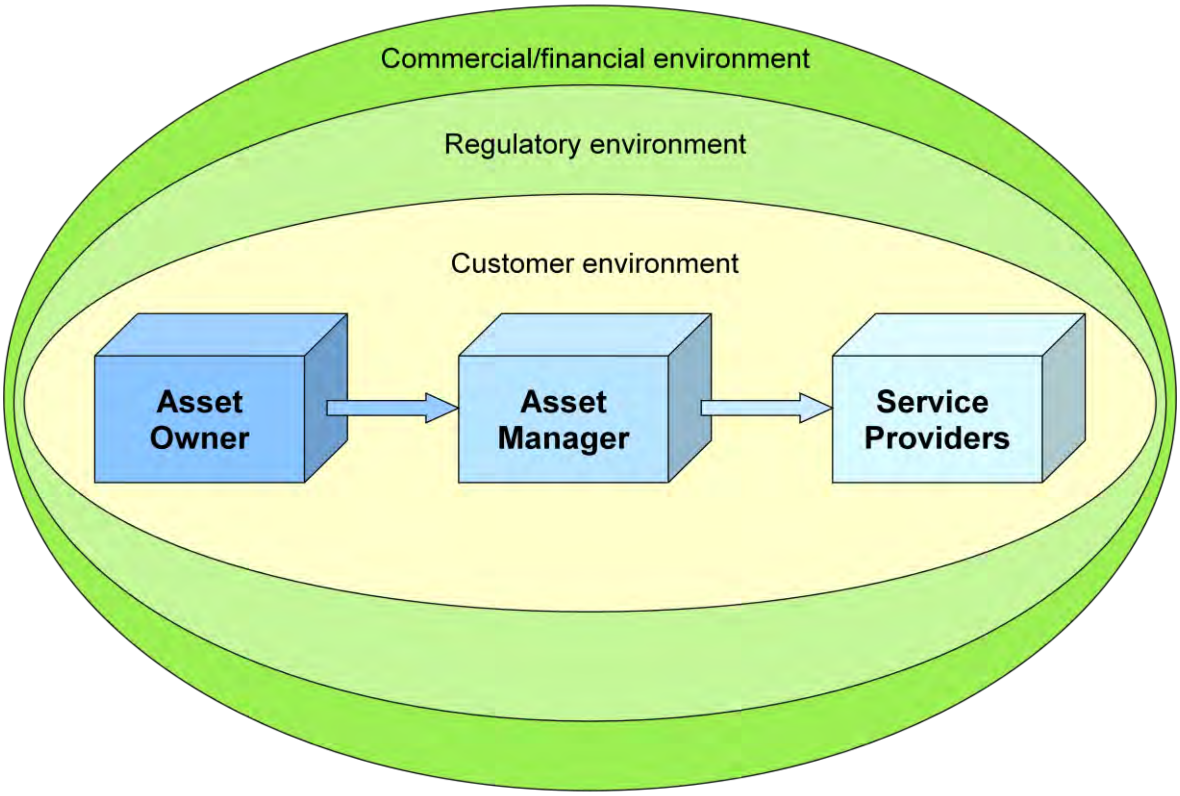

Figure 1-1 : Vector's asset management framework

In this model, the asset owner is the highest level of management within the organisation that owns the assets – in Vector's case 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 between regulatory issues and other stakeholder requirements.

The asset manager is that part of the organisation that develops asset strategy, directs asset risk management, asset investment and asset maintenance planning, and decides where and how asset investment is made – in Vector that is, broadly, the Asset Investment group (AI). The asset manager sets policies, standards and procedures for the service providers to carry out.

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. In Vector the service providers are a combination of the Service Delivery group (SD) - capital programmes, network operations and service operations - and the external contractors and consultants supporting them.

Asset management occurs within a context strongly influenced by customer, commercial, financial and regulatory demands and strategies.

- Customer needs and desires, along with safety and technical regulations, form the very basis that determines the make-up of electricity networks. Network layout and capacity is designed to ensure that 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 - are likewise based on customers' requirements and the value they place on the reliability of supply.

  In the Vector environment, most direct interaction with customers occurs through the Commercial group. Asset management at Vector involves close interaction with this group to assist with understanding consumer requirements, consumption forecasts and upcoming developments.

- The regulatory environment can be seen as a proxy for the market in which we operate (this refers to economic regulation). In addition there are also technical regulations around how networks are allowed to be built and operated. Not only does regulation influence technical network parameters such as the extent of assets installed and the levels of spare capacity in the assets themselves[4], but it also limits the commercial returns on investments and hence directly influences investment decisions. There are also a number of regulatory compliance rules that have an impact on network configuration and operations. Lastly, the asset manager has to provide support for regulatory submissions and information disclosures.

  In Vector, 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. Capital investment and maintenance policy decisions have to reflect this, providing an appropriate balance between the needs of running a sustainable network and achieving appropriate commercial returns on investments. Not only do investment decisions have to be demonstrated to be economically efficient[5], but all realistic alternative options have to be investigated to ensure that the most beneficial solution – technically and commercially – is applied. This may involve taking a view on likely future technical changes in the energy sector.

  Regulatory certainty is critical to the investment framework, given the long term nature of the assets – hence prior regulatory commitments are clearly central to ongoing investment certainty.

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

  Asset management at Vector, in particular where expenditure is involved, therefore requires close interaction with the Finance group.

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[4] Through setting the optimisation guidelines that apply during valuation of the regulatory asset base.

[5] Either through demonstrating an appropriate economic return, or the need of the investment to ensure network sustainability.

In the context described above, a Vector internal asset management business plan was developed to define Vector's asset management policies, responsibilities, targets, investment plans and strategies to deal with the future of the electricity network.

While this business plan's emphasis is on electricity network asset management, it is very much a Vector-wide document. 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 the overall Vector 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.

1.1.1 The Role of the Disclosure Asset Management Plan

The regulatory disclosure Asset Management Plan (the AMP - this document), is largely drawn from Vector's internal asset management plan and strategies. However, the AMP, being a publicly disclosed document and being subject to a prescribed contents structure differs in some instances from the internal documents, namely:

- The internal asset management business plan and strategies form a key platform to capture in depth our asset management thinking, strategies, detailed plans and forecast expenditure build-ups. They are therefore wider in scope, and more detailed than the AMP;
- Information that is commercially or strategically sensitive to our customers or to Vector is not disclosed in the AMP;
- The regulatory timeline requires reporting on a 1 April to 31 March financial year, whereas the Vector year is from 1 July to 30 June; and
- Asset management practices or interactions with other parts of the wider business that Vector considers important, but that are not required for the regulatory AMP structure, are omitted.

The internal and disclosed plans are however consistent and the disclosed plan contains sufficient, accurate information to keep Vector's customers and other interested parties well-informed about our asset management practices and our intended development plans, in accordance with the regulatory requirements and Information Disclosure Handbook guidelines.

1.2 Planning Period and Approval Date

This AMP covers a ten year planning period, from 1 April 2010 through to 31 March 2020 and was approved by the Board of directors on 23 March 2010. The first five years of the plan are based on detailed analysis of customer, network and asset information and hence provide a relatively high degree of accuracy in the descriptions and forecasts. The second five years of the plan are based on less certain information and an accordingly less detailed level of analysis, and are only suitable for provisional planning purposes.

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 1 April 2010.

The purposes of this AMP are:

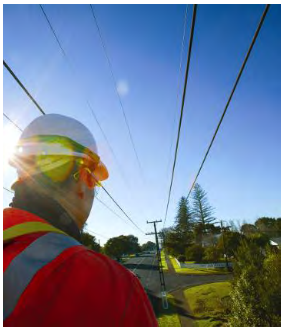
- To inform stakeholders how Vector intends to manage and expand its electricity distribution network based on information available at preparation;
- To ensure the Commerce Commission understands the impact of regulatory settings on future investment decisions;
- To demonstrate alignment between electricity network asset management and Vector's goals and values;
- To demonstrate innovation and efficiency improvements;
- To provide visibility of best practice asset management at Vector;
- To provide visibility of forecasted electricity network investment programmes and upcoming medium-term construction programmes to external users of this AMP;
- To discuss Vector's views on expected technology and consumer developments and the asset investment strategies to deal with a changing environment; and
- To meet Vector's regulatory obligation in terms of the aforementioned requirement 7.

This plan 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 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 Zealanders' 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.

These are supported by the strategies of the various business units in Vector. Asset management, as captured in the internal asset management business plan and also discussed 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 internal asset plan supports Vector's vision is demonstrated in Figure 1-2 below.

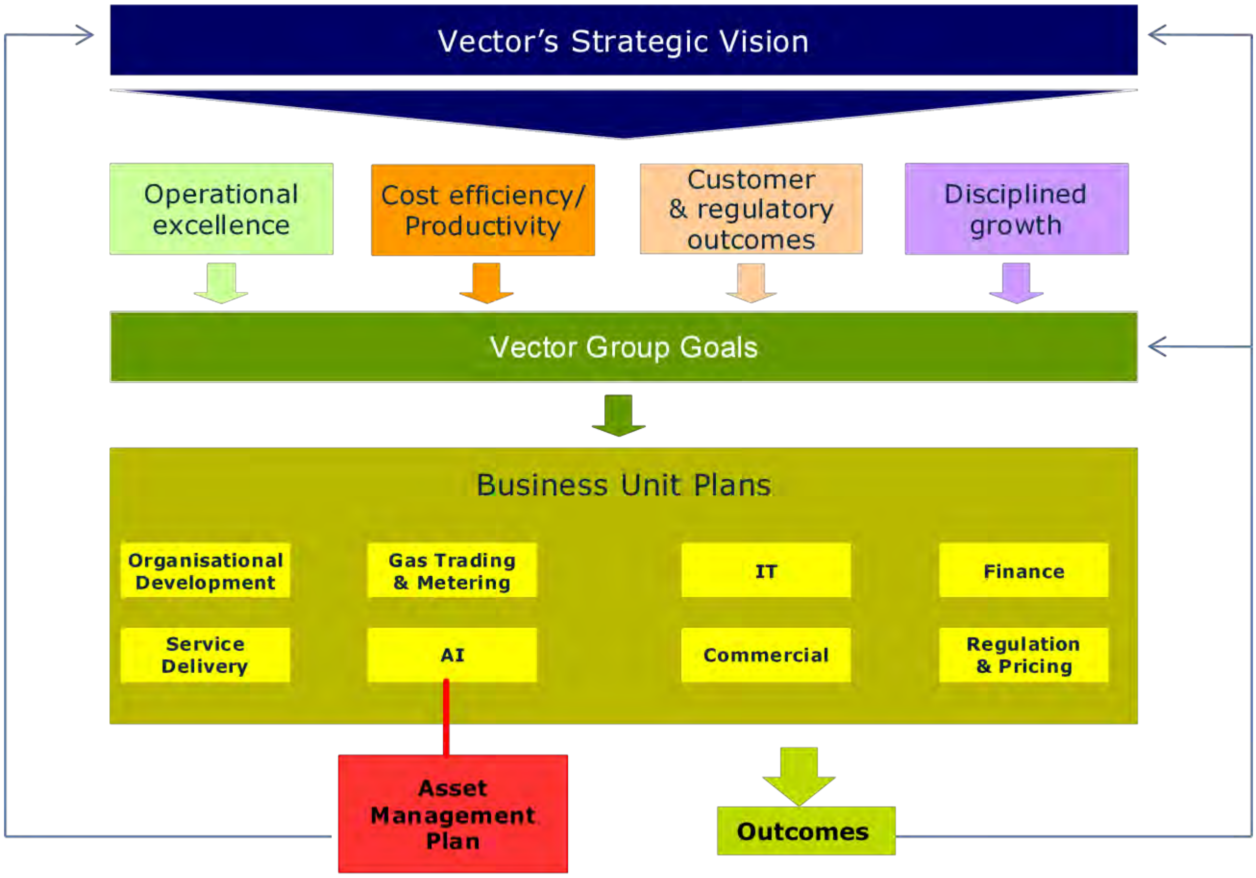


Figure 1-2 : The AMP in support of the overall Vector strategic vision

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

Group Goal	Asset Management in support of
Disciplined Growth	♦ Investigate new technologies & associated opportunities
	♦ Optimise financial contributions ♦ Support commercially attractive investments
	♦ Innovation & optimal efficiency ♦ Optimising investment decisions ♦ Economies of scale from long-term view
Customer & Regulatory Outcomes	♦ Technical excellence ♦ Providing reliable service
	♦ Fit-for-purpose network designs ♦ Understanding & reflecting customer needs in designs ♦ New customer solutions and choice ♦ Security & reliability levels adapted to customer needs ♦ Maintaining appropriate price/quality trade-off
	♦ Reliable asset information source ♦ Detailed five-year expenditure budgets ♦ Strategic scenario planning
	♦ High quality network planning ♦ Best practice maintenance planning
Operational Excellence & Cost Efficiency / Productivity	♦ Investigate new technologies & opportunities offered
	♦ Clear prioritisation standards ♦ Needs clearly defined ♦ Understanding risks
	♦ Fit-for-purpose network designs ♦ Providing reliable service ♦ Security & reliability levels adapted to customer needs ♦ Easy-to-maintain & operate networks
	♦ Safe networks is top priority ♦ Full compliance with health, safety & environmental regulations
	♦ Clear roles & responsibilities for asset management ♦ Strong, well-documented asset management processes
	♦ Support sustainability of partners ♦ Clear communication of network standards & designs

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

1.3.2 Vector's Vision Driving Asset Management

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

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

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, listed in the table below, reflect the manner in which AI understands and implements Vector's strategic direction.

KEY PREMISES FOR THE AMP	
Safety will not be compromised.	Safety of the public, our staff and our contractors is paramount. Asset management must drive this.
A deteriorating asset base will be avoided.	In general, assets will be replaced when they are obsolescent, reach an unacceptable condition, can no longer be maintained or operated, or suffer from poor reliability. (In a small number of instances where it is technically and economically optimal and safety is maintained some assets will be run to failure before being replaced.)
The networks will fully adhere to safety regulations & standards.	Vector complies with New Zealand safety codes, prescribed network operating practices and regulations.
Regulatory requirements will be met	Regulatory requirements with regards to information disclosures 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 & 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. Gold-plating or excess assets are not acceptable. Investments must provide an appropriate commercial return.
Existing reliability and supply quality levels will generally be maintained.	The Commerce Commission's quality path regulations support maintaining current levels of quality. Some localised exceptions (where customers require specific supply quality levels, or on poorly performing parts of the network) will be made, reflecting price/quality trade-offs as appropriate.
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.
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 communicated to affected parties. The security standards are based on Vector's best understanding of customer requirements and the price/quality trade-off.

KEY PREMISES FOR THE AMP	
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, excessive performance deterioration, age-profiles should be monitored and appropriate advance actions taken.

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 previous AMP was prepared at a time when a major economic slowdown was anticipated. It was anticipated that this downturn would reduce network growth for a period of two to three years before the economy was expected to recover. This growth expectation was reflected in the capex programme, with reduced growth Capital Expenditure (capex) over the next couple of years.

However, in reality the maximum network demands recorded in 2009 were materially higher than that predicted. The actual customer connection expenditures for both residential and commercial sectors were also significantly higher than the corresponding forecasts and budget for the 2009/2010 financial year. This higher than expected growth in peak capacity requires a number of network capacity projects to be reinstated.

The Government has brought forward a number of roading and infrastructure projects, such as the Waterview tunnel construction. The increased level in roading and infrastructure activities by local and central government agencies caused a corresponding increase in asset relocation requirements. These projects have been included in the latest expenditure forecast.

The net effect of all of these adjustments is that the timing difference in the previous AMP has had to be reversed, and in some cases new investments have become necessary to accommodate relocation or customer growth requirements. This is reflected in the forecast expenditure levels stated in the AMP (see Section 9).

1.4.2 Formation of the Auckland Council

From 1 November 2010, the eight district, city and regional councils of Auckland will be amalgamated into a single council structure under Auckland council.

The final structure and organisation of the Auckland Council is still being established with key decisions made to date including the establishment of a single council, seven Council Controlled organisations (CCO) and 21 local community boards. Key structural changes include the establishment of CCO's to manage the transport and water service needs for the region.

The changes being made may have a significant impact on Vector's activities in the region. A number of key relationships with regional councils will change and the management of our existing activities across the region will transfer to new entities and likely new roles.

The new structure is still being established and it is currently not clear how utility interests will be managed or where responsibilities for these issues will sit in the new structure. Vector will continue to work closely with the Auckland Transition Agency and existing council contacts to understand the changes and promote structures that will facilitate efficient outcomes in the region.

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 internal asset management business plan also provides visibility of asset management activities to the rest of the company, for incorporation into the broader business plans and strategies. In Figure 1-3 and Figure 1-4, this two-way support flow is illustrated.

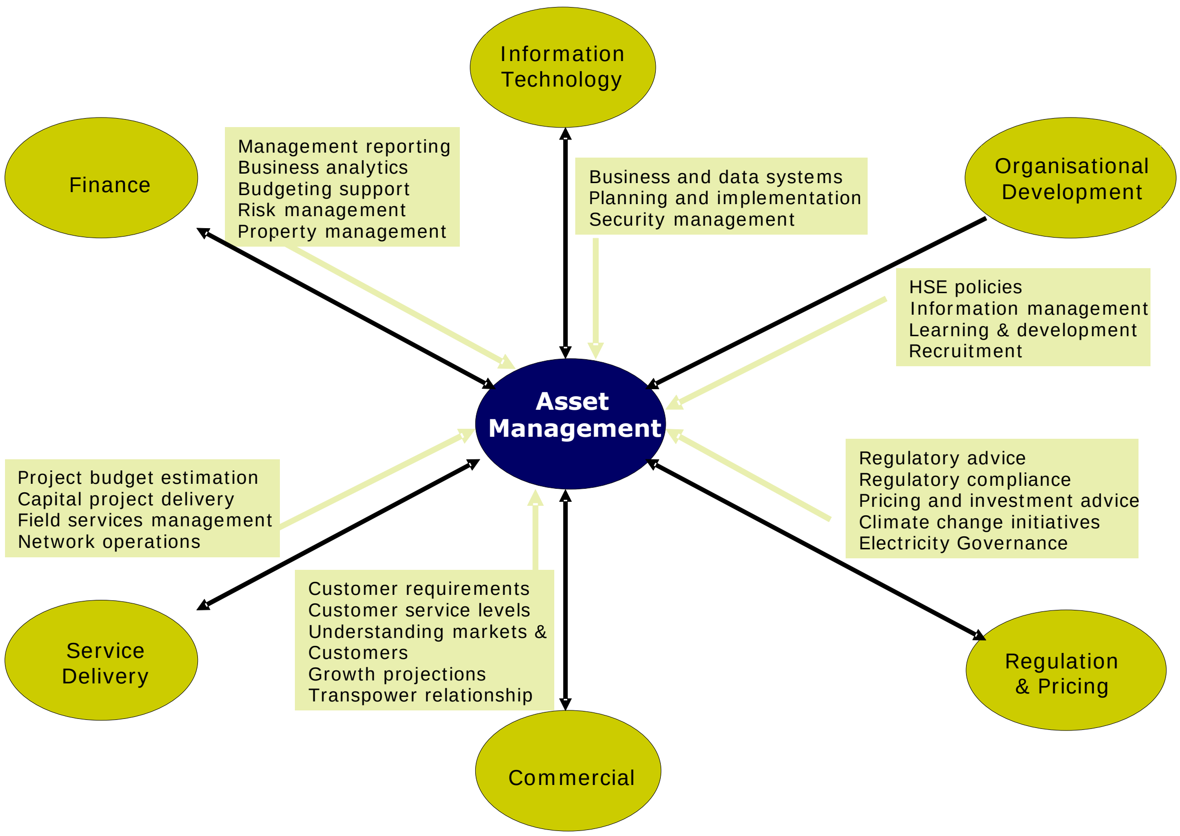


Figure 1-3 : Interaction with the rest of Vector – the flow into asset management

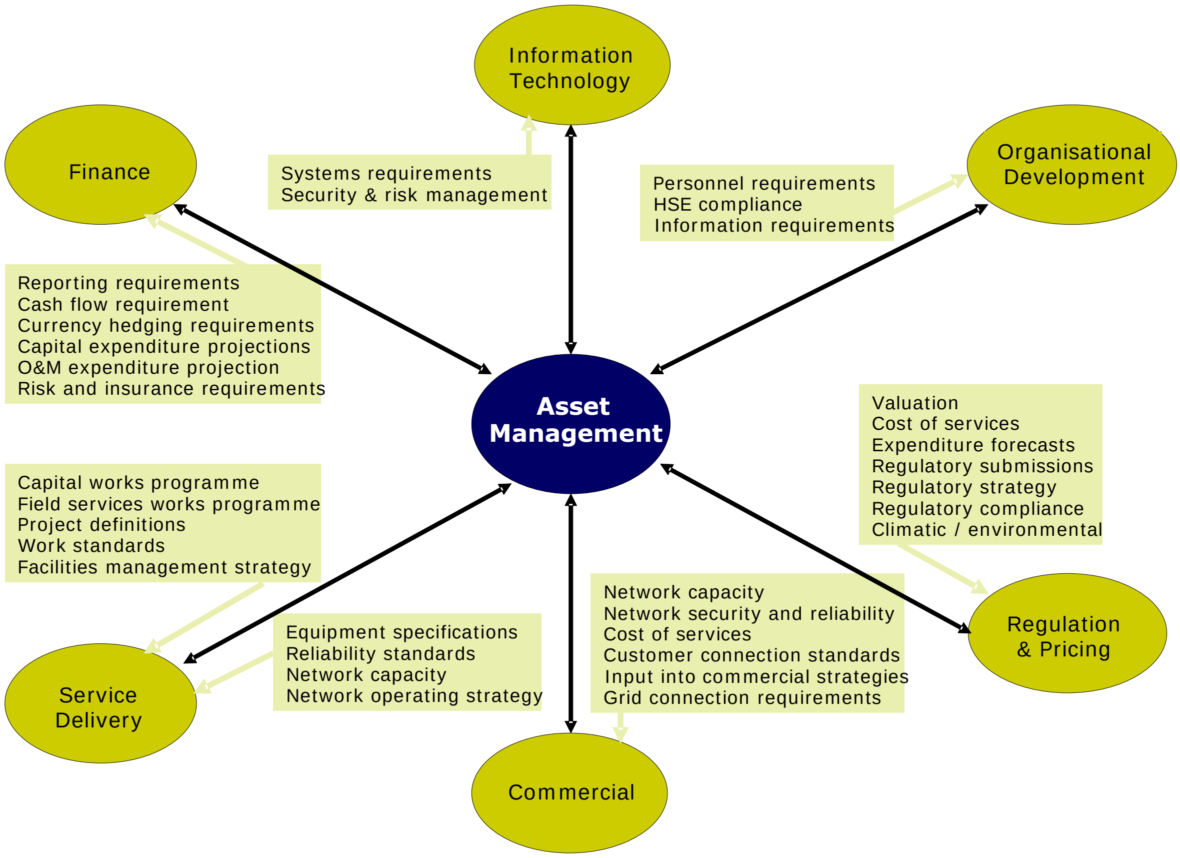


Figure 1-4 : Interaction with the rest of Vector – the flow from asset management

1.6 Asset Management in the Wider Vector Context – External Stakeholders

As with any commercially focused business, 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 product we sell, its importance to the national well-being, gives rise to some stakeholders with a keen interest in how we conduct our business.

In Figure 1-5, the important external stakeholders in 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.

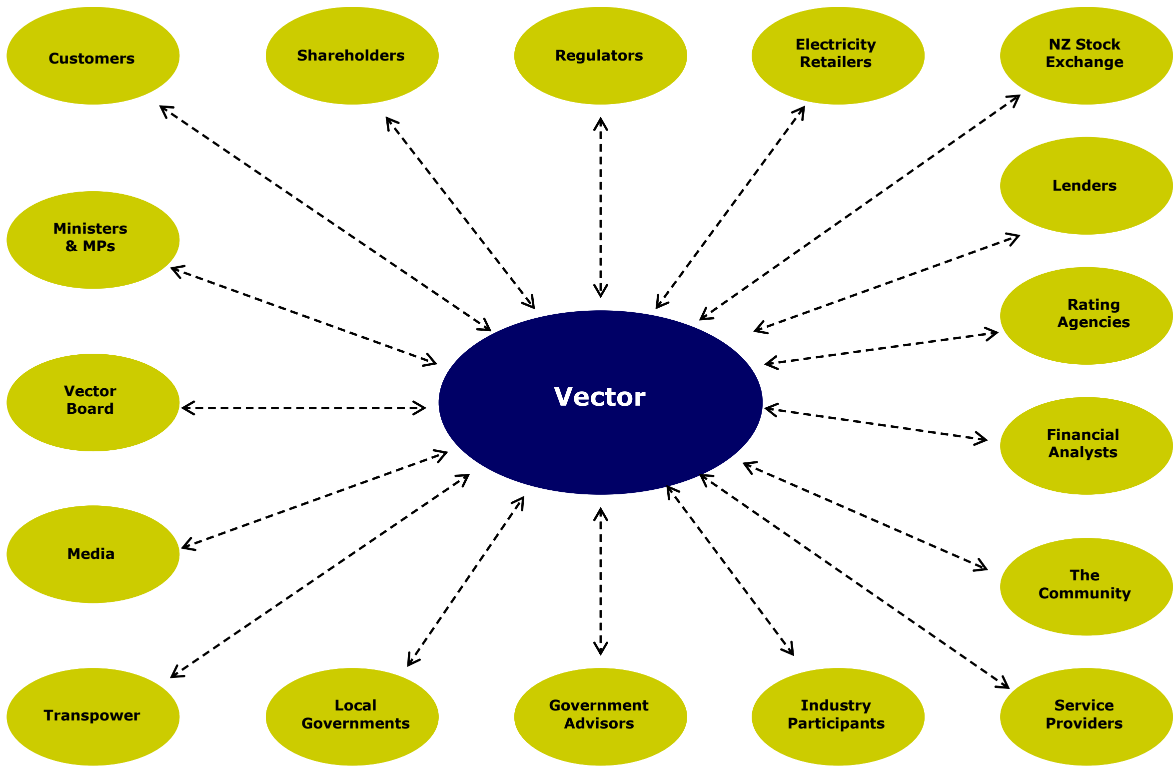


Figure 1-5 : Vector's key external stakeholders

Stakeholder Expectations

Stakeholder expectations are listed in the table below.

Customers (end use consumers)	
▪ Reliable supply of electricity ▪ Quality of supply ▪ Security of supply ▪ Efficiency of operations ▪ Fair price ▪ Timely response to outages	▪ Information in fault situations ▪ Planned outages ▪ Timely response to complaints and queries ▪ Health and safety ▪ Environment ▪ Timely connections
Shareholders	
▪ Return on investment ▪ Sustainable growth ▪ Reliability	▪ Regulatory compliance ▪ Prudent risk management ▪ Good reputation
Retailers	
▪ Reliability of supply ▪ Quality of supply ▪ Managing customer issues	▪ Information in fault situations ▪ Ease of doing business ▪ Good systems and processes
Regulators	
▪ Statutory requirements ▪ Accurate and timely information	▪ Inputs on specific regulatory issues ▪ Fair competitive behaviour

Vector Board

- Return on investment
- Regulatory compliance
- Good governance
- Accurate and timely provision of information
- Expenditure efficiency
- Prudent risk management
- Reliability of supply
- Health, safety and the environment
- Accurate budgeting

New Zealand Stock Exchange

- Compliance with market rules
- Accurate performance information
- Good governance
- Financial forecasts

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 & MPs

- Security of supply
- Reliable supply of electricity
- Efficient and equitable markets
- Industry leadership
- Investment in infrastructure and technologies
- Environment
- Good regulatory outcomes

Local Government

- Compliance
- Environment
- Coordination between utilities
- Sustainable business
- Support for economic growth in the area

Community

- Good corporate citizenship
- Community sponsorship
- Electricity safety programme
- Visual and environmental impact
- Engagement on community-related issues
- Improvement in neighbourhood environment

Energy Industry

- Participation in industry forums
- Leadership
- Innovation
- Policy inputs
- Influencing regulators & government
- Sharing experience & 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

We ascertain our stakeholders' expectations by:

- 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;
- Local community meetings;
- Media enquiries and meetings with media representatives; and
- Monitoring publications and media releases.

We accommodate stakeholders' expectations in our asset management practices by:

- Providing a safe and reliable distribution network;
- Quality of supply performance meeting consumers' needs;
- Optimisation of capital and operational expenditures (opex);
- Maintaining a sustainable business that caters for consumers' growth requirements;
- Comprehensive risk management strategies and contingency planning;
- Due consideration of the health, safety and environmental impact of Vector's operations;
- Compliance with regulatory and legal obligations;
- Security standards reflecting consumers' needs;
- Network growth and development plans;
- Provision of accurate and timely information;
- Development of innovative solutions; and
- Comprehensive asset replacement strategies.

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 1.3.2);
- 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 compromise, or commercial solution.

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

- Cost/benefit analysis;
- Long-term planning strategy and framework;
- Environmental impact;
- Societal impact;
- 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.

1.7 Asset Management Structure and Responsibilities

1.7.1 Senior Level Organisation Structure

The Vector senior level organisation structure is provided in Figure 1-6 below. The Vector group is split into several functional areas, each with a responsible general manager.

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 that these two sections play in asset management is further discussed in Section 1.7.2 and Section 1.7.3.

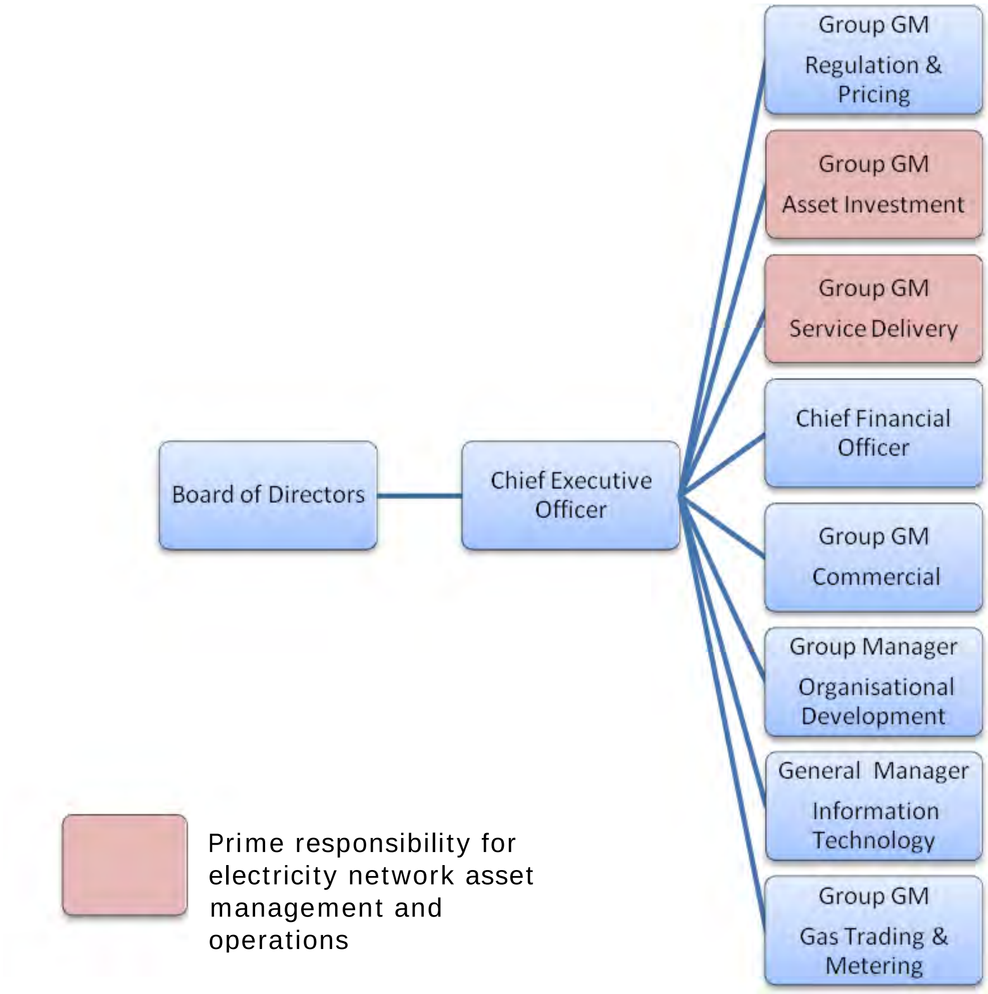


Figure 1-6 : The Vector senior management structure

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

- Regulation and Pricing

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

- Finance

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

- Commercial

  Key customer relationships, mass market customer relationships, customer connections, public relationships, commercial strategies, Vector Communications and energy consumption projections.

- Organisational Development

  Human resource management, training and development, recruitment, health, safety and environmental policies, and personnel performance management.

- Information Technology (IT)

  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 (AI)

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:

- Ensuring that asset investment at Vector is efficient and provides an appropriate commercial return to the company's shareholders;
- Ensuring that the configuration of the electricity network is technically and economically efficient, that it meets customer requirements, and is safe, reliable and practical to operate;
- Planning network developments to cater for increasing electricity demand or 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 the Auckland Electricity Consumer Trust's obligations with regard to undergrounding networks in the Southern region are met.

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

In Figure 1-7 the structure of the AI group is expanded, emphasising the electricity network asset management responsibilities.

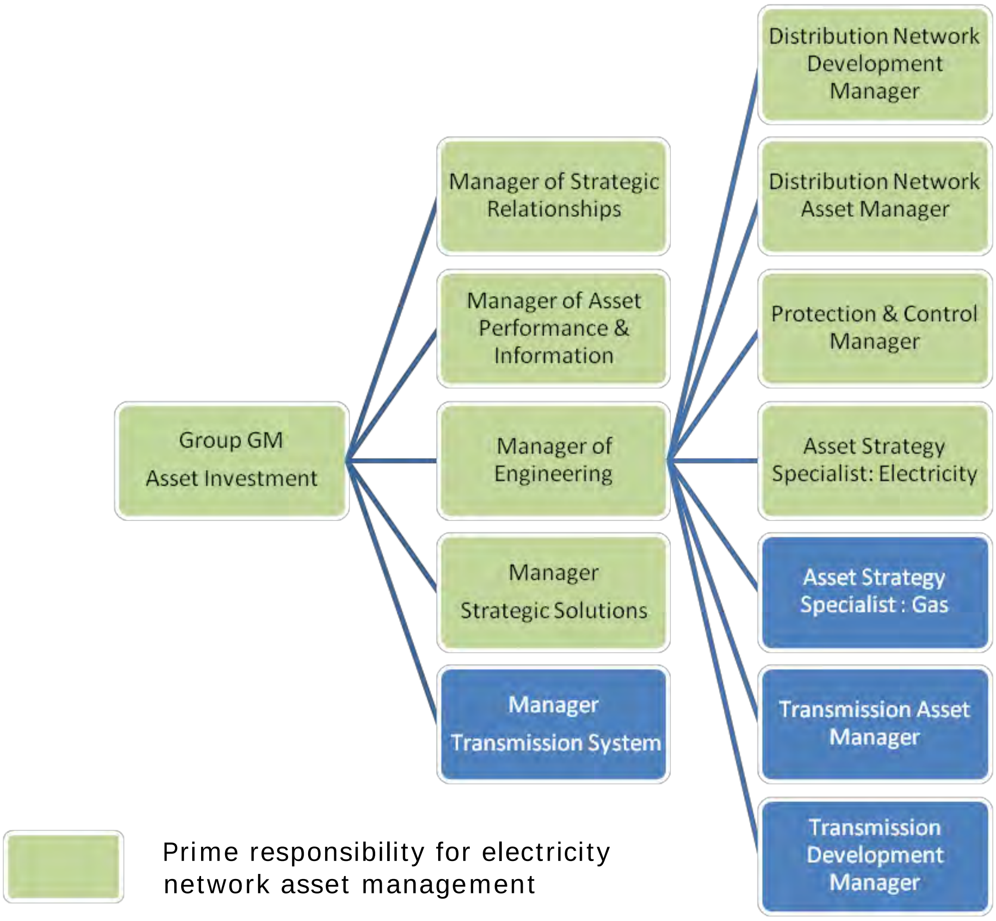


Figure 1-7 : The Asset Investment management structure supporting the AMP

1.7.3 The Service Delivery Group (SD)

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 team delivers on providing, operating and maintaining the assets.

This 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, is illustrated in Figure 1-8 and further expanded below.

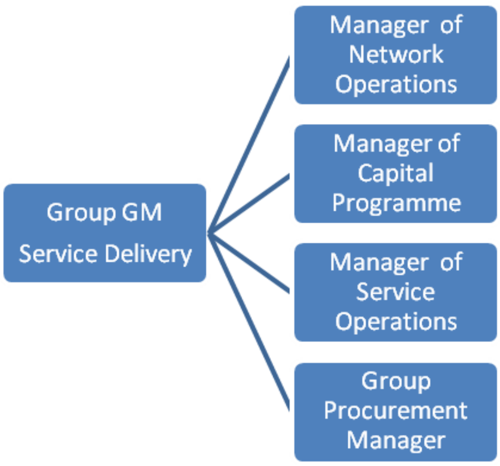


Figure 1-8 : Service Delivery as an asset management service provider

Network Operations

This section is responsible for the day-to-day operational management of the network. It includes the control room, from where asset 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 "user" of the network, this team interacts closely with the asset manager, particularly on the following:

- Defining user requirements;
- Planning network configuration;
- Setting safe asset operation levels (short and long-term);
- Investigating outages and the root causes – especially if asset-related; and
- Contingency management.

Capital Programme

This 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 by our contracted service providers partners (Northpower and Electrix), which were selected through a competitive tender process. In some instances work is also done by other contractors sourced on a competitive tender basis[6].

The Capital Delivery team and AI 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.

Service Operations

This section is responsible for the maintenance of the electricity network. This is done in conjunction with Vector's service provider partners (Northpower and Electrix).

[6] 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.

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

- Implementation of the maintenance policies;
- Setting maintenance budgets;
- Managing replacement of mass assets (e.g. poles, cross-arms or distribution transformers)[7], including project progress and expenditure reporting;
- Feedback on asset performance; and
- Investigating asset failures.

Procurement

This 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
- Cost estimation.

1.7.4 Asset Management Activities by other Groups

While the bulk of electricity network asset management activities at Vector are performed by AI, supported by SD, as noted in Section 1.5 the rest of Vector also 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.

Commercial

The Commercial group is responsible for new customer connections. For large connections, which require core network extensions or could have material capacity implications, the installations are generally managed by AI and SD as part of the normal core network growth projects[8]. Provision of smaller connections is directly managed by the Commercial group – through the Vector service providers.

Information Technology

There is increasing overlap of electricity network assets and information technology. Not only does asset management require sophisticated information systems, but the traditional SCADA networks is with time becoming less of a stand-alone electricity network application with unique requirements and protocols, and more of a conventional IT network application. Increased security of both SCADA and Communications is being provided for. Procurement and implementation of IT support systems, and the core SCADA equipment, is managed by the Information Technology group.

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

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

Vector Communications

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[9]. Provision of this service is on a strict commercial basis, with AI 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). The terms of engagement for FSPs were first developed in 1999 when the field services work in the Vector supply area (Southern region) was contracted to three providers. This was later reduced to two following the expiry of the contract and a review of the performance of the FSPs and the needs of the company at the time. The merger with United Networks network (Northern region) in 2002 increased the total number of service providers back to three (to include United Network's FSP).

In 2008 and the early part of 2009 a review of the contracting business model was carried out to examine:

- Whether the outsourcing model should continue or Vector should establish its own in-house field service resources; and
- If the preferred model was to outsource, what process would be adopted to determine the framework of the relationship, the optimum number of FSPs and their capabilities, the structure of a new contract and the selection of preferred FSPs.

After an extensive investigation 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.

Although still in a relatively early stage of its implementation, Vector is already starting to see some of the benefits from the new field service contracts becoming apparent.

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. Finally, the AMP is reviewed and approved by Vector's CEO and Board.

[9] 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.

1.8.1 Alignment with the Vector Budgeting Process

Vector operates under a July to June financial year. The internal 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[10].

The disclosure AMP, as previously discussed, draws from the internal asset management plans and processes, and it therefore represents the same view on future network requirements, including capital and maintenance expenditure requirements at the time of its preparation. However, the disclosure AMP is prepared for a regulatory timeframe, which does not correspond with Vector's financial years. There are therefore timing differences between the ten year forecasts in Vector's internal plans and this AMP.

1.8.2 The Expenditure Forecasting Process

In Figure 1-9 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 budget to implement the works programme is developed. This is an unconstrained budget;
- 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.

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

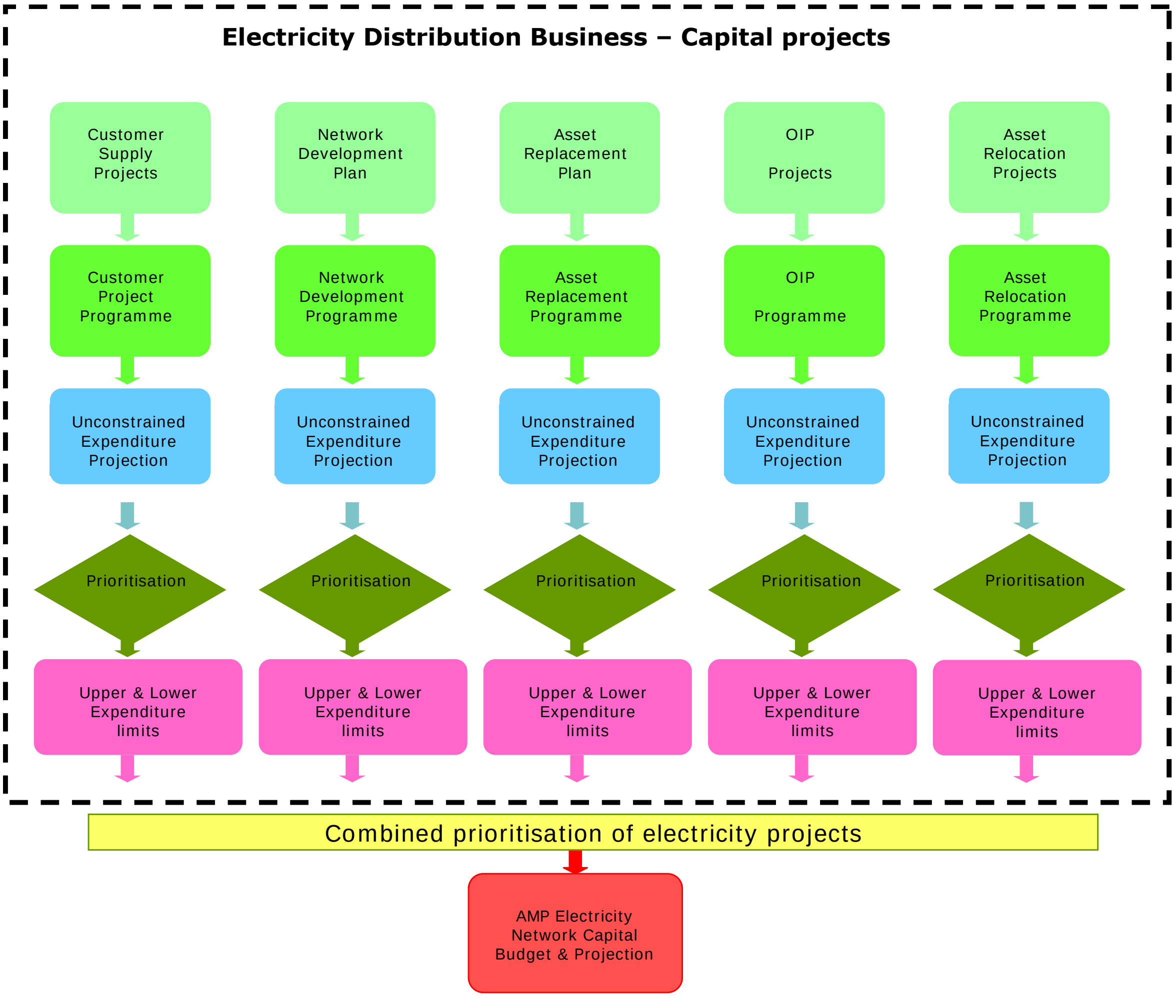


Figure 1-9 : Capex forecasting process adopted for the AMP

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 project 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 may 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.

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:

- Overall expenditure against budget;
- Progress of key capital projects against project programme and budget;
- Performance of key assets such as sub-transmission cables;
- Health, safety and environmental issues; and
- Network reliability.

1.11 Asset Management Processes

The diagram in Figure 1-10 shows the high level asset investment process within Vector. This highlights the relationship between the different asset creation and evaluation processes within Vector.

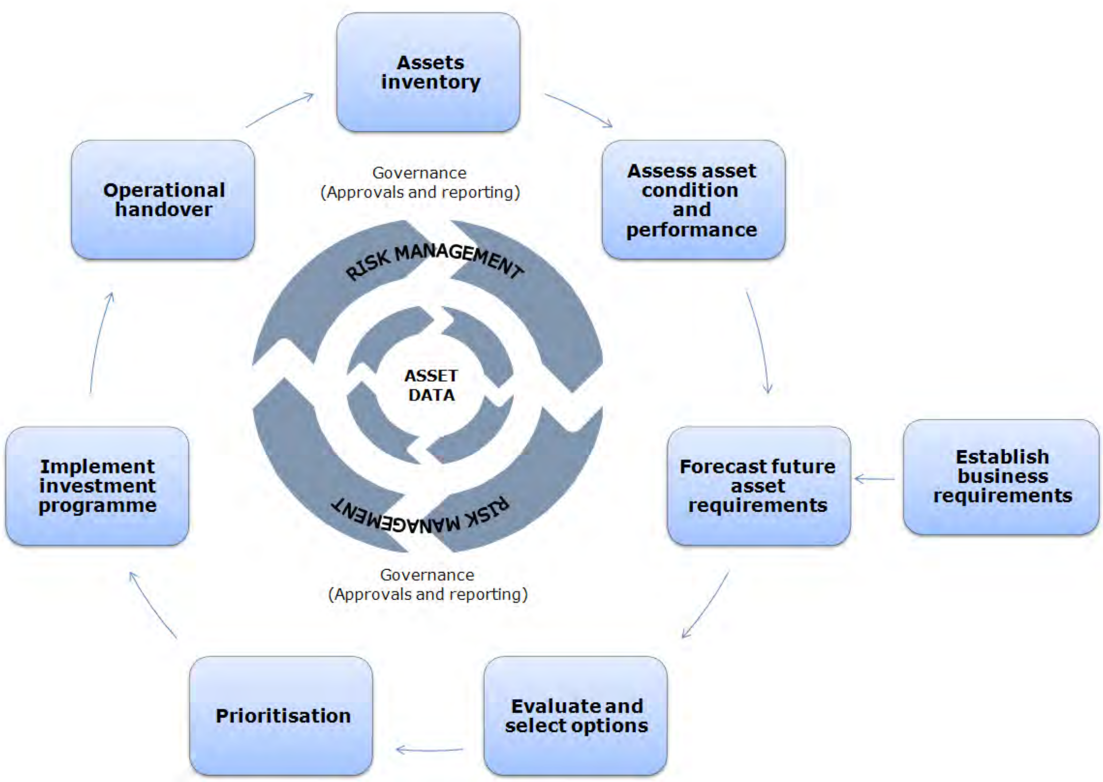


Figure 1-10 : High-level overview of the Vector asset investment process

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 Asset Condition and Performance

Information on the performance, utilisation and condition of existing assets is needed to forecast future investment, renewal or upgrading requirements. This requires ongoing monitoring of asset performance and condition, the consumption of resources associated with particular 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.

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 3, Section 5 and Section 6 discuss this information.

We operate 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.

At Vector we broadly categorise 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
- Maintenance planning is undertaken to ensure that 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 that only those projects that meet the company'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 Section 5, Section 6 and Section 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 that 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) teams. For larger projects, the Capital Programme team as part of SD develops the conceptual solution into a detailed design suitable for implementation. Contracts are let to approved service providers for the execution of these projects.

Service Operations (a team within SD) 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 that 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 asset specialists who take assets over and arrange the maintenance regime. The GIS 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 (Section 1).

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 past year, Vector has put extensive effort into further improving the coordination of the various activities associated with the delivery of the capital works programme with the objective of better utilisation of resources, enhance 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 regulatory year 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, local councils and their service providers. These works coordination processes have been focused on maintaining effective communication channels with external agencies, identifying cost effective future proofing opportunities, minimise 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. Over the last year this has resulted in a number of win-win outcomes.

1.13 Other Asset Management Documents and Policies

The internal asset management business plan is the main document for capturing and communicating the asset management strategies for the electricity network. As noted before, this regulatory AMP draws from that plan. In addition, Vector has a number of other documents that are used to capture asset management polices and particulars. (Including all of these in one document would produce a totally unwieldy, impractical plan).

In addition, there are a number of company-wide policies that have a direct bearing on asset management. These are listed below.

1.13.1 Other Asset Management Documents

The AMP is supported by a collection of detailed asset management documents and policies. These include:

- 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 pre-employment 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 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; and
- Capex policy.

Information Technology:

- Access policies;
- Password and authentication policy;
- Network management policy;
- Internet use policy;
- Email 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;
- 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 predominantly very positive in their feedback – confirming that asset management at Vector conforms with best-practice – we have taken note of the feedback and recommendations received, and where practical and beneficial, reflected this in our asset management practices.

1.15 Cross Reference to the Information Disclosure Requirements

As indicated earlier (Section 1.1), this disclosure AMP was prepared based on Vector's internal asset management business plan. 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 by the Commerce Commission's Asset Management Plan (2009 – 2019) compliance review.

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	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	Not applicable
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 1, 5, 6 and 7
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

[11] "Handbook Clause" refers to the clause as stated in the "Electricity Information Disclosure Requirements".
[12] "Handbook Requirements" refers to the requirements as stated in the "Electricity Information Disclosure Requirements".
[13] "Interpretation" refers to the interpretation of the requirement as expressed in Strata's "Compliance review of Electricity Distribution Business Asset Management Plans for period beginning 1 April 2009".

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
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.* 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.	Does the AMP summary highlight information that the EDB considers significant?	Executive Summary
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*	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.	Section 1.1
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	Sections 1.3, 1.4, 1.5, 1.6 and 6.2.

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	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.*	and mission statements? Do the objectives show a clear recognition of stakeholder interest?	
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 1.3, 1.5 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, 1.11, 5.1 and 6.2
4.5.2c **7(3)a**	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**		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);	Does the AMP identify the EDB's important stakeholders and	Sections 1.5 and 1.6

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	Explanation: Recognising and accommodating stakeholder interests are key parts of the AMP. AMPs should therefore identify important stakeholders and indicate:	indicate:	
4.5.2.di	*(i) how the interests of stakeholders are identified;*	- how the interests of stakeholders are identified;	Section 1.6
4.5.2.dii	*(ii) what these interests are;*	- what these interests are;	Sections 1.5 and 1.6
4.5.2.diii	*(iii) how these interests are accommodated in asset management practices; and*	- how these interests are accommodated in the EDB's asset management practices: and	Sections 1.5 and 1.6
4.5.2.div	*(iv) how conflicting interests are managed.*	- 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 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 1.8, 1.9 and 1.10
4.5.2eii	*At the executive level the AMP should provide an indication of how the in-house asset management and planning organisation is structured.*	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 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 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?	Section 1.7
4.5.2f	f) details of asset management systems and processes, including asset management systems/software and information flows. *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*	Does the AMP identify the key systems used to hold data used in the asset management process? Does it describe the nature of the data held in each system and what this data is used for?	Sections 7.1 and 7.3

Handbook Clause [11]	**Handbook Requirements [12]**	**Interpretation [13]**	**AMP Reference**
	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.*	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, 5.1 and 6.2
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.*	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 7.2 and 7.3
4.4.6 c		If there is a problem with data accuracy or completeness, does the AMP disclose initiatives to improve the quality of the data?	Sections 7.3 and 7.4
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	Section 2.2

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
		network, if any?	
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;* *(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.*	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;	Section 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, including identification and capacity of zone substations and the voltage of the sub-transmission network;	Sections 2.3, 5.4, 5.8
4.5.3.bii		- the extent to which individual zone substations have n-x sub-transmission security;	Section 5.4
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	Does the AMP include a description of the assets that make up the distribution system	Section 6.3

<table>
<tr><th>Handbook Clause [11]</th><th>Handbook Requirements [12]</th><th>Interpretation [13]</th><th>AMP Reference</th></tr>
<tr><td></td><td rowspan="2">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;
- 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.</td><td>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?</td><td></td></tr>
<tr><td>4.5.3c</td><td>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;
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</td><td>Section 6.3</td></tr>
</table>

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
		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
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*	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

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	urban and rural areas.		
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?	Section 4.2
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 5.2
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 5.3
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*	Does the AMP describe the process and criteria for prioritising network developments?	Sections 5.3 and 5.7
4.5.5c		Does the AMP describe the load forecasting methodology, including all the factors used in	Section 5.4

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	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.*	preparing the estimates?	
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?	Section 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?	Sections 5.4 and 5.8
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 5.4
4.5.5c		Does the load forecast take into account the impact of any demand management initiatives?	Section 5.4
4.5.5c		Does the AMP identify anticipated network or equipment constraints due to forecast load growth during the planning period?	Sections 5.4 and 5.8
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?	Sections 3.2, 5.4 and 5.5
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.*	Does the AMP discuss the manner in which the EDB seeks to identify and pursue economically feasible and	Section 5.6

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	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.	practical alternatives to conventional network augmentation in addressing network constraints?	
4.5.5e		Does the AMP discuss the potential for distributed generation or other non-network solutions to address identified network problems or constraints?	Section 5.6
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 5.8
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*	Does the AMP include : a detailed description of the projects currently underway or planned to start in the next twelve months;	Sections 5.8 and 5.12
4.5.5g		a summary description of the projects planned for the next four years; and	Sections 5.8 and 5.12
4.5.5g		a high level description of the projects being considered for the remainder of the planning period?	Sections 5.8 and 5.12
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?	Section 5.8
4.5.5g		For other projects that are planned to start in the next five years, does the AMP discuss	Section 5.8

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	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.*	alternative options, including the potential for non-network alternatives to be more cost effective than network augmentations?	
4.5.5g		Does the AMP include a capex budget, broken down sufficiently to allow an understanding of expenditure on all main types of development projects?	Section 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; *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.*	Does the AMP provide a description and identification of routine and preventive inspection and maintenance policies, programmes, and actions to be taken for each asset category, including associated expenditure projections?	Section 6.3
4.5.6b		Does the AMP describe the process by which defects identified by its inspection and condition monitoring programme are rectified?	Section 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 budgets for routine maintenance activities, broken down by asset	Unable to comply (data not available in the required category).

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
		category, for the whole planning period?	Introduction of Systems Applications and Processes (SAP) in April 2010 is expected to rectify the situation.
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 6.7
4.5.6dii		- a summary description of the projects planned for the next four years; and	Section 6.7
4.5.6diii		- a high level description of the other work being considered for the remainder of the planning period?	Section 6.7
4.5.6e **7(2)a**	e) asset replacement and renewal expenditure (which must be separately identified in the capital budget). *Forecast expenditure and reconciliations shall be provided and prepared in accordance with Appendix A.*	Does the AMP include a budget for renewal and refurbishments, broken down by major asset category, and covering the whole of the planning period?	Section 6.7

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
		Does the AMP include details of the EDB's risks policies and assessment and mitigation practices including:	Sections 8.1 and 8.3
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.	- methods, details and conclusions of risk analysis;	Section 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	*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.*	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?	Sections 6.3 and 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.*	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	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.*	Is the progress of development projects against plan (as presented in the previous AMP) assessed and are the reasons for substantial variances highlighted? Are any construction or other problems experienced discussed?	Section 5.12
4.5.8	*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*	Is the actual maintenance expenditure compared with that planned in the previous AMP and the reasons for significant	Section 9.4

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	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 *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.*	differences discussed?	
4.5.8		Is progress against maintenance initiatives and programmes assessed and discussed and is the effectiveness of these programmes noted?	Unable to comply (maintenance programmes not provided in the previous plan). This will be included in the next plan.
4.5.8		Is the measured service level and asset performance for the previous year presented for all the targets discussed under the Service Levels section of the AMP?	Sections 4.1 and 4.2
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, 4.2 and 4.3
4.5.8c		Does the AMP review the overall quality of asset management and planning within the EDB and discuss any initiatives for improvement?	Sections 1.14, 5.13, 6.5 and 7.4
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*	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	Section 9.4

Handbook Clause [11]	Handbook Requirements [12]	Interpretation [13]	AMP Reference
	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).	for which data is available.	
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?	Sections 1.3
7.2		Are the significant assumptions presented and discussed in a manner that makes their source(s) and impact(s) understandable to electricity consumers?	Sections 1.3 and 1.4
7.2		Does the AMP identify assumptions that have been made in relation to the sources of uncertainty?	Sections 1.3 and 1.4

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 network) and south to Papakura (Southern network). The map in Figure 2-1 shows the network boundaries, with Northpower in the north and Counties Power in the south. In addition, Vector supplies a large customer at Lichfield which is a standalone supply. While Vector operates this as a single network, it is convenient to describe a Southern region and a Northern region.

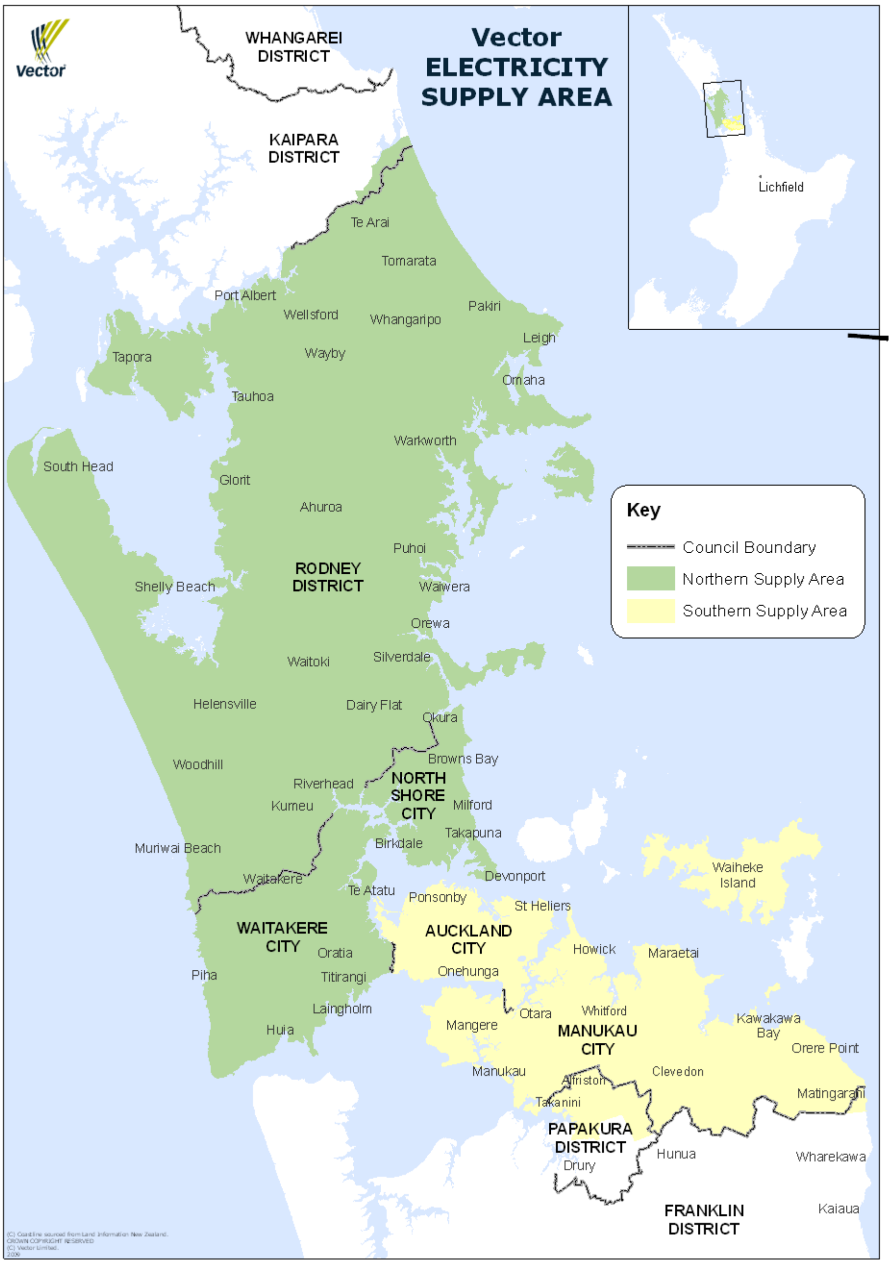


Figure 2-1 : Vector electricity supply area

The creation of a new Auckland City this year will affect working relationships and local body policies.

2.1.1 Northern Network

The Northern region covers those areas administered by North Shore City Council, Waitakere City Council and Rodney District Council, and 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 plan to expand the motorway network north of the Albany basin, it is expected that urban development will continue to move northwards.

2.1.2 Southern Network

The Southern region covers areas administered by Auckland City Council, Manukau City Council and Papakura District Council, and 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 whole region. Development density in the Auckland region tends to be higher than in other regions. 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 above 5MVA and are considered to have a significant impact on network operations and asset management:

- Fonterra cheese factory at Lichfield;
- Auckland International Airport;
- Mangere Waste Water Treatment Plant;
- Owens Illinois;
- Fisher & Paykel appliance factory at East Tamaki;
- Pacific Steel;

- Ports of Auckland;
- Laminex Penrose;
- Coca Cola Amatil (NZ) Limited;
- Devonport Naval Base;
- Carter Holt Harvey, Penrose;
- Masport Limited; and
- Westfield NZ Limited – Albany, St Lukes, Manukau.

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 increases equipment ratings. However, we anticipate a strong trend towards installing new residential appliances such as heat pumps (refer Section 3), with indications that some winter peaking residential feeders and substations will change to 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. It can be seen that the residential load has two peaks whereas the commercial load is consistent for the whole 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.

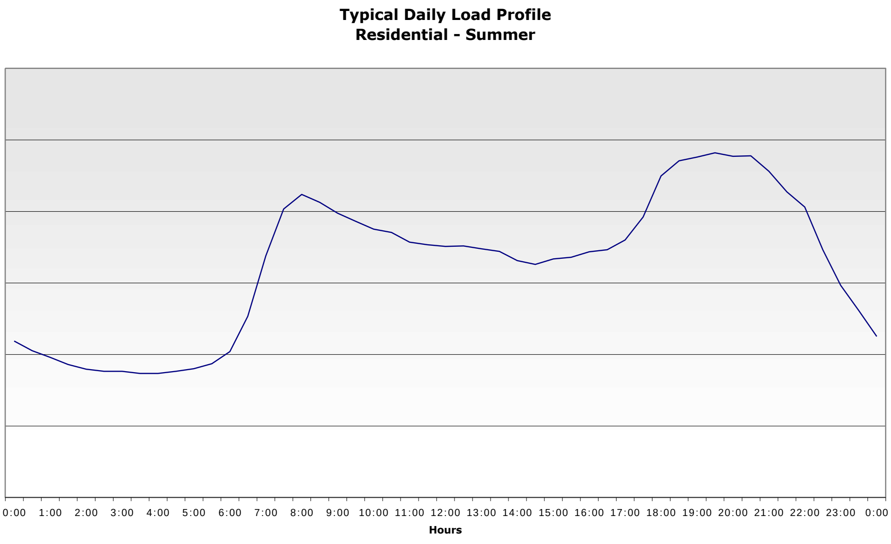


Figure 2-2 : Typical summer load profile for residential customers

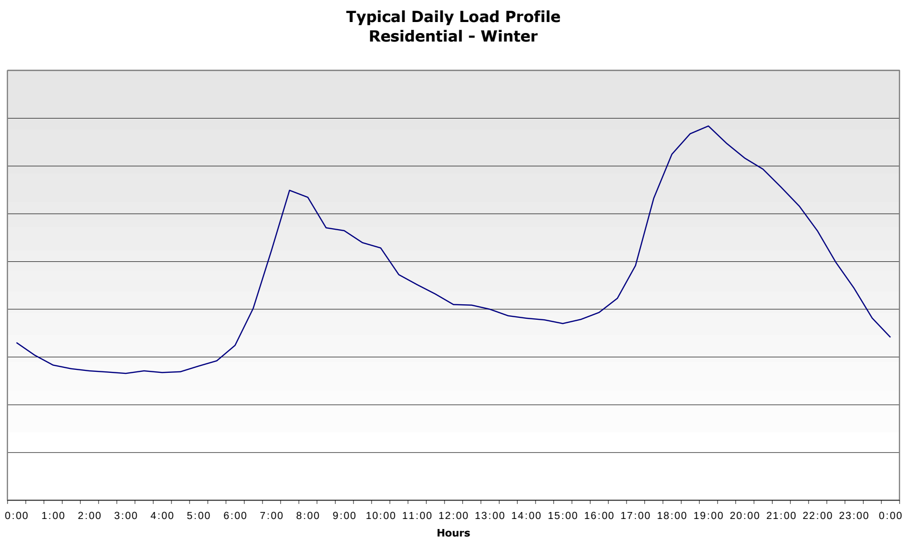


Figure 2-3 : Typical winter load profile for residential customers

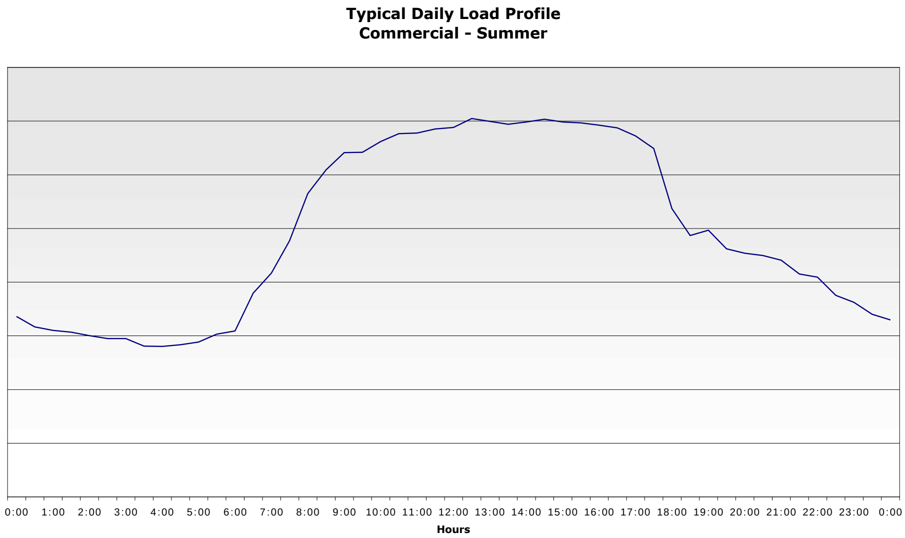


Figure 2-4 : Typical summer load profile for commercial customers

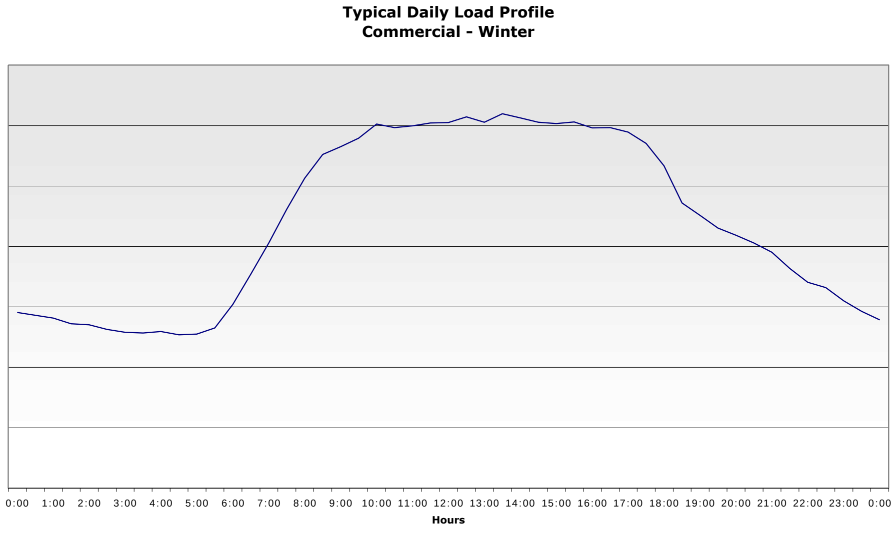


Figure 2-5 : Typical winter load profile for commercial customers

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 consumers 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 two years is listed in Table 2-1. (The individual demand forecasts for zone substations on Vector's network are detailed in Section 5.6).

Calendar Year	Northern Peak Demand (MW)	Southern Peak Demand (MW)	Combined Peak Demand (MW)	Northern Energy Delivered (GWh)	Southern Energy Delivered (GWh)
2008	596	1134	1676	2565	5638
2009	603	1111	1711	2556	5688

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

The values reported above are the coincidental peak demands of all Grid Exit Points (GXPs) delivering supply to Vector, as well as major embedded generation. The major embedded generators (capacity > 1MW) are at Greenmount, Whitford, Redvale and Rosedale landfill sites and at Auckland Hospital, but excludes Southdown which is a notionally embedded generator (connected at 220kV to the Otahuhu to Henderson line and has no direct physical connection to the Vector network).

Lichfield is included in the Northern region on the above table.

2.3 Network Configuration

The overall architecture of the Vector network is shown in Figure 2-6. The network is made up of three main component networks: transmission, sub-transmission and distribution.

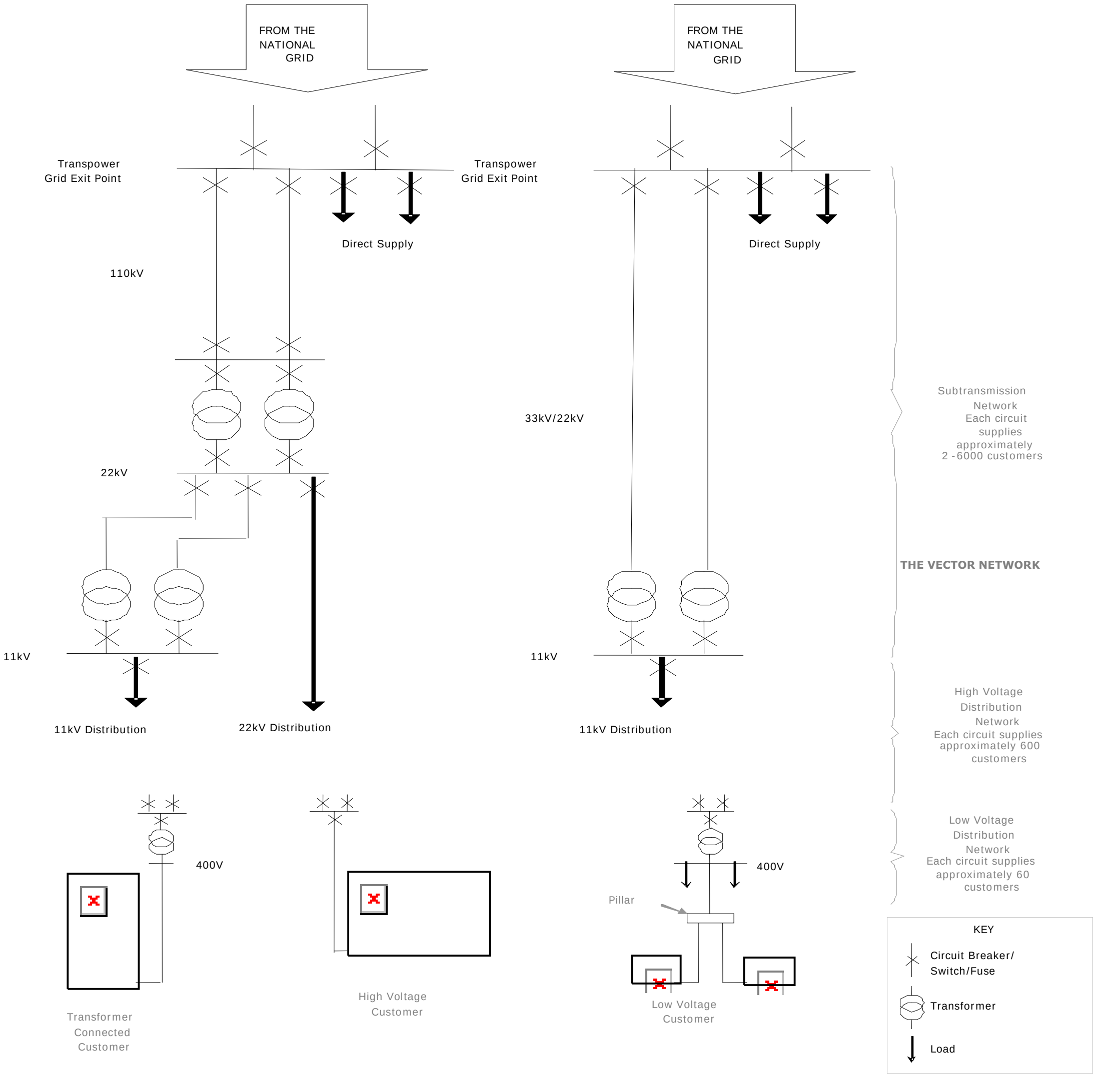


Figure 2-6 : Schematic of Vector's network

2.3.1 The Transmission Grid around Auckland

Vector takes supply from the national grid at 13 GXPs to supply its sub-transmission network. Supply is taken at 110kV, 33kV and 22kV. It has also established five bulk supply substations to supply its sub-transmission networks that are at a distance from the grid.

The following tables show the winter and summer peak demands at GXPs and bulk supply substations for the Southern and Northern regions including Lichfield. The tables also show the installed capacity and firm capacity at each of these supply points.

Grid Exit Point	Installed Transformer Capacity (MVA)	Firm Capacity (MVA)[14]	2009 Peak Demand Winter (MVA)
Mangere 110kV			64.8
Mangere 33kV	2*120	108	94.9
Otahuhu 22kV	2*50	60	56.1
Pakuranga 33kV	2*120	136	136.2
Penrose 110kV			189.5
Penrose 33kV[15]	2*160, 1*200	427	331.9
Penrose 22kV	3*45	90	68.2
Roskill 110kV			40.8
Roskill 22kV	2*70, 1*50	141	111.4
Takanini 33kV	2*150	123	115.9
Wiri 33kV	1*100, 1*95	107	70.7
Albany 110kV		286	138.0
Albany 33kV	3*120	248.5	152.8
Henderson 33kV	2*120	135	101.7
Hepburn 33kV	1*85, 2*120	205	125.8
Silverdale 33kV	1*120, 1*100	120	71.2
Wellsford 33kV	2*30	30	30.2
Lichfield 110kV	2*20	24	6.9

Table 2-2 : Bulk electricity supply points for Auckland and Lichfield winter loads

Grid Exit Point	Installed Transformer Capacity (MVA)	Firm Capacity (MVA)[1]	2009 Peak Demand Summer (MVA)
Mangere 110kV			53.2
Mangere 33kV	2*120	108	81.2
Otahuhu 22kV	2*50	60	44.2
Pakuranga 33kV	2*120	136	88.1
Penrose 110kV			219.0
Penrose 33kV[2]	2*160, 1*200	404	272.0
Penrose 22kV	3*45	90	56.0
Roskill 110kV			35.5
Roskill 22kV	2*70, 1*50	141	71.8
Takanini 33kV	2*150	123	66.3
Wiri 33kV	1*100, 1*95	107	65.4
Albany 110kV			88.1
Albany 33kV	3*120	288	103.7
Henderson 33kV	2*120	144	72.7
Hepburn 33kV	1*85, 2*120	222	94.8
Silverdale 33kV	1*120, 1*100	120	43.0
Wellsford 33kV	2*30	30	22.0
Lichfield 110kV	2*20	24	6.9

Table 2-3 : Bulk electricity supply points for Auckland and Lichfield summer loads

[14] Firm capacity is the cyclic capacity as determined by Transpower. Reinforcement is indicated if the load exceeds the firm capacity

[15] includes 22kV load

2.3.2 The 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 regions 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 bus), 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 sub-transmission network and the zone substations is given in Section 5.12 of this plan.

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 existing 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 generally.

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 2009, 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.

2.3.3 Distribution Network

The function of the distribution network is to deliver electricity from the zone substation to customers. It includes a system of cables and overhead lines, operating at 6.6kV, 11kV, or 22kV, which distribute electricity from the zone substations to smaller distribution substations. Typically anywhere between one and 2,000 customers are supplied by high voltage (HV) distribution feeders, the number determined by the load 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 a HV (22kV, 11kV or 6.6kV) / LV transformer, LV board and HV 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.

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 Section 5.12 of this AMP.

2.3.3.1 Undergrounding

The Auckland Electricity Consumer Trust (AECT), which owns 75% of Vector, has an undergrounding programme for the Southern network 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 2009, 68% of the distribution (6.6kV, 11kV and 22kV) network was underground in the Southern region and 30% in the Northern region. Overall, 45% 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.

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 2009, 61% of the LV distribution network was underground in the Southern region and 47% in the Northern region. Overall, 55% 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 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 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 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 (RTUs, 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 networks, while LN2068 is used for the Northern region. Vector's modern substation automation system and other field IEDs installed in recent years have been, and continue to be, interfaced to both SCADA master stations, enabling migration process 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 consumer 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.

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).

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 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 that 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;
- 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 traditionally been very 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[16].

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 5.2.3 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 a 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 line companies in New Zealand and Australia.

[16] And 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.

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

- Equipment standardisation

  To minimise cost in the long term and to ensure that 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, we have standardised on 20MVA and 10MVA for power transformers - 20MVA transformers are used in high 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 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 implies that the lowest cost short-term solution may not always be adopted. For example, we build 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.

3. Future Vision and Strategy

3.1 Overview

The environment within which electricity distribution companies operate is presently undergoing considerable change, and Vector is no exception to this:

- 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[17], or causing stranded or inappropriate assets[18]; 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 rapidly changing environment pose interesting challenges. Vector has therefore developed a future vision to help guide asset management strategy, to ensure not only that our networks can cope with the anticipated changes, but also that we are well-positioned to make best use of the opportunities offered.

The Vector asset management strategy is also based on an all-encompassing continual efficiency improvement drive, ensuring that we achieve optimal returns on investments while providing a reliable, safe and affordable electricity supply.

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 over the next three years. The target will be achieved through a combination of continual improvement and innovation, in a number of ways:

- Keeping an open mind ("how we can" not "why we can't");
- Broadening our 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 that others are applying and relating these to our 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
- Making continuous incremental improvements in our project planning and delivery.

[17] Through increasing electricity demand peaks.
[18] When equipment becomes obsolete at an early date, or demand shifts lead to redundant capacity.

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 mitigating strategies to reduce any adverse effect these technologies may have on the network.

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 parts. Technology developments are now making it operationally feasible to extend to the lower voltage parts of the network.

The outcomes from this offer the potential to:

- Improved asset utilisation resulting in deferred investment expenditure;
- Increased network reliability and reduced 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 our existing systems, which will inform our future strategies in this regard.

One area of concern that will have to be addressed is the regulatory and pricing implications of investment in emerging technologies. From a societal perspective there may be clear efficiency gains achievable through adopting the emerging technologies, but it is less clear that the regulatory framework and the New Zealand electricity market structure allows appropriate incentives or rewards for any particular sector of the market, including electricity lines business, to unlock the full available potential. If the correct regulatory long term incentives are not in place the efficiency gains will not be made.

Vector's "intelligent network" strategy is detailed in Section 3.3 below.

3.2 Future Technology Assessment

3.2.1 Selection of Technologies for Assessment

A broad scan of technologies that could impact on Vector's networks has been undertaken, as illustrated in Figure 3-1:

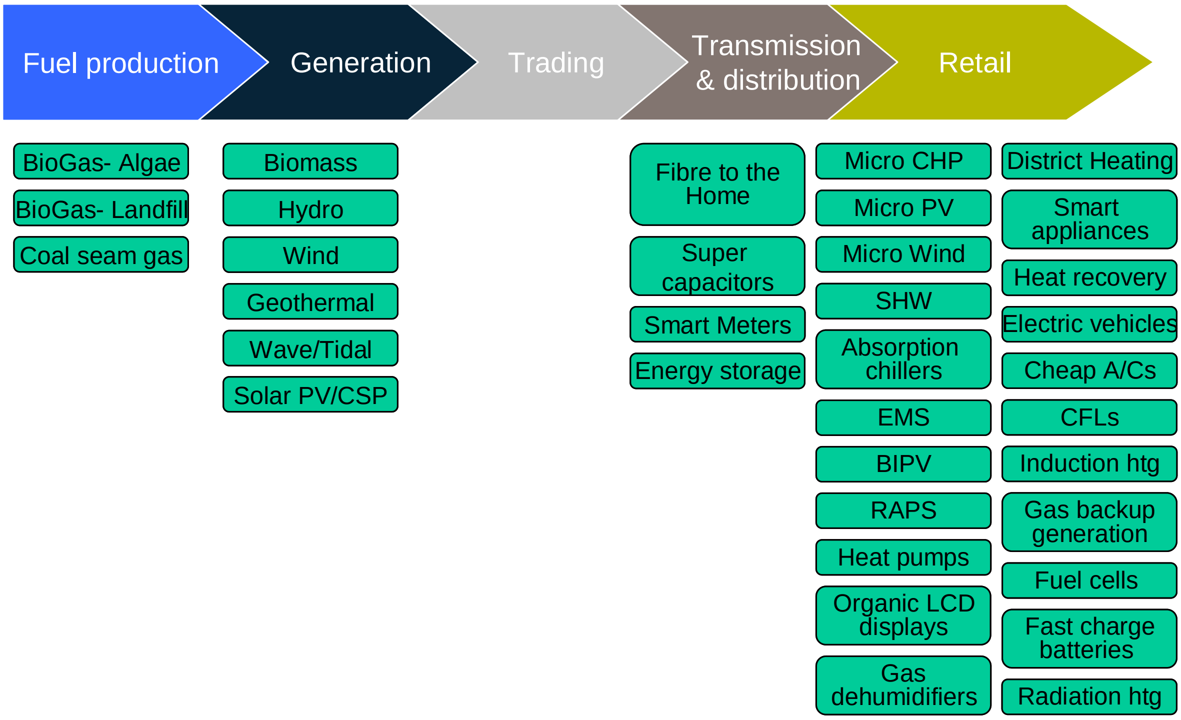


Figure 3-1 : Emerging trends considered for the Technology Roadmap Project

Our evaluation of the impact a technology may have on the network and its likelihood to emerge is summarised in Figure 3-2, where the size of the technology bubble indicates the likelihood of emergence of the technology. The further away the technology bubble is from the origin, the higher the impact (positive and negative) on the electricity network is expected to be. The grey circle shows the area where the impact is expected to be low to moderate - technologies outside the circle are expected to have a greater impact.

The technologies that are more likely to have significant impact on the electricity network are:

- Heat pumps;
- Photo-voltaic (PV) panels;
- Electric vehicles; and
- Smart home technologies.

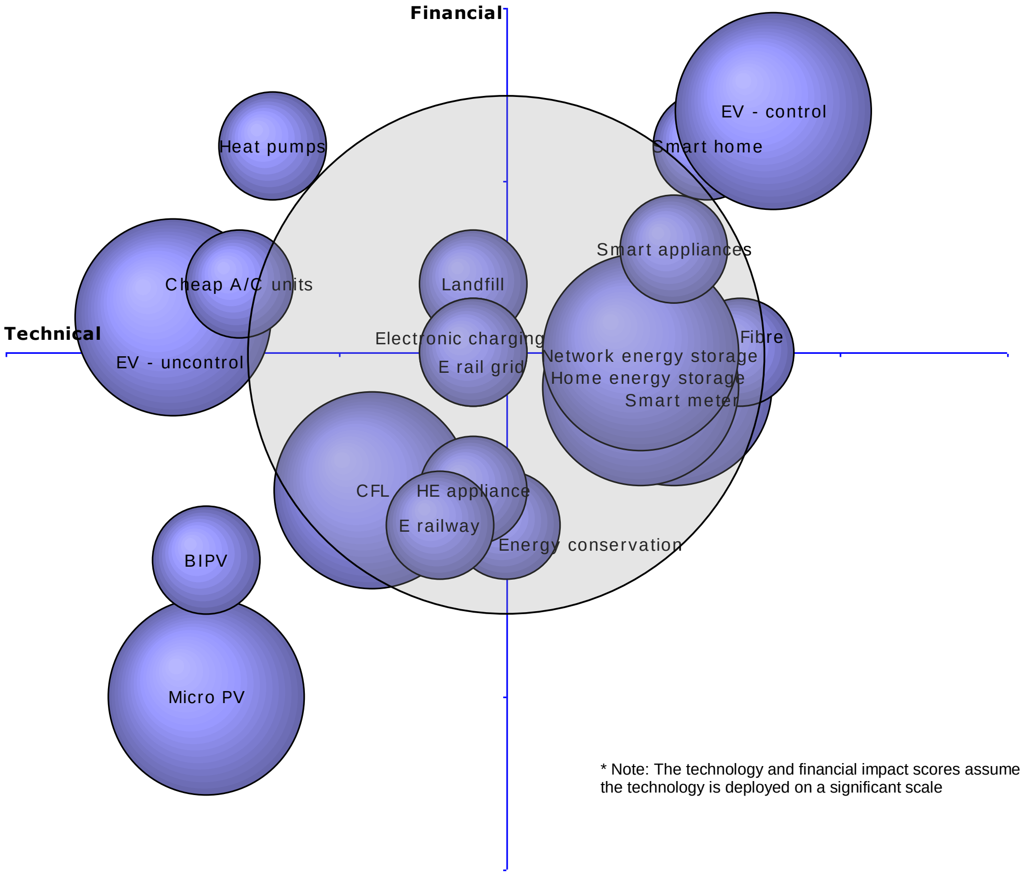


Figure 3-2 : Screening assessment results

A brief summary of the drivers and key network impact of these technologies is provided in Table 3-1.

It is also noted that fuel cells and V2G[19] (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 a natural progression from the use of electrical vehicles, and is hence dependent on the uptake of electric vehicles and future development of battery and charging technologies. Development of both these technologies will be closely monitored.

[19] V2G is the short description for vehicle to grid. This describes the use of the energy stored in the batteries of an electric vehicle to supply the electricity network at times when the grid has difficulties supplying the customer's needs.

	Photo Voltaic cells	Electric Vehicles	Smart Homes	Heat Pumps
Description	Mass installation of solar PV on residential homes and commercial property with the potential to export surplus energy to the grid	Mass usage of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). Degree of network control for EV charging is key driver of network impact. Emergence of V2G supply will be a key step in technology evolution	Emergence of smart appliances, home area networks (HANs), smart meters and smart control systems to optimise the energy use within the home	Large uptake of A/C units and heat pumps for summer cooling and winter heating
Key market drivers	When manufacturing prices have fallen far enough for PV supplied electricity to reach grid parity. (This also applies to direct energy supply, without converting to electricity - for example using solar cells for water heating.)	Reduction in battery costs; increase in battery efficiency and charging rate and range of vehicles available; availability of charging infrastructure	Emergence of smart appliances; installation of "smart" home energy management and communications platform; emergence of HANs; development of home control software; design of new tariff structures making use of improved metering capabilities	Continued cost reductions in A/C units driving higher demand; lifestyle considerations.
Likely timing for wide-spread introduction	2-5 years	10-20 years	5-10 years	Already occurring
Key network impacts	Reduction in grid-supplied energy consumption (but not peak demand); large/rapid changes in energy flows (including reverse flow) and potential over-voltage situations	Large/peaky demand that could coincide with general peak demand periods; 2nd generation V2G; need for network control of charging behaviour; large infrastructure reinforcement required	Improved load control system capability; integration of smart home into network system management; demand-based distribution tariffs; voluntary load limiting	Potential shift to summer peak across Vector network; network reinforcement or peak reduction to handle summer loads; initial winter load reduction

Table 3-1 : Drivers and key network impact of technologies with a significant impact on the electricity network

3.2.2 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 that the relevant and appropriate experience has been applied.

3.2.2.1 Solar PV

Solar PV pricing is predicted to fall to a level which makes its $/kWh ratio on par with solar water heating by about 2013. Assuming a similar rate and allowing for a 10% increase per year in installations as price continues to fall, this will lead to a 5% penetration of the housing stock in Auckland within 15 years, increasing to 10% within 20 years. By comparison, in Germany, where PV subsidies have effectively provided low pricing for the past ten years, the penetration rate is now around 5%.

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) electricity will 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 will be maintained, it is therefore not foreseen that the delivery capacity can be reduced as PV is introduced.

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

The following two graphs in Figure 3-3 and Figure 3-4 show the potential changes to feeder asset utilisation and impacts on zone substation backstop capacities due to PV installation.

Feeder utilisation is a measure of how well the capacity of a feeder has been utilised and is defined, in this context, as the ratio of the peak demand carried by the feeder and the rating of the feeder. The higher the demand on a feeder, the higher the utilisation becomes. Increase in PV generation may offset part of the demand and hence reduce utilisation. This will consequently enhance supply security.

Backstop capacity to a zone substation is a measure of the capacity available to back up a zone substation under a contingent event from neighbouring substations via the distribution network. An increase in PV generation may reduce demand on the distribution network and neighbouring substations, making more back up capacity available to the zone substation under contingent events.

The graphs were prepared on the assumption that the contribution from PV generation is a certainty and hence presented a picture showing the upper limit of optimism. In practice, due to the intermittent nature of PV generation, that is generation will not always displace demand, the situation is worse off than the diagrams suggest.

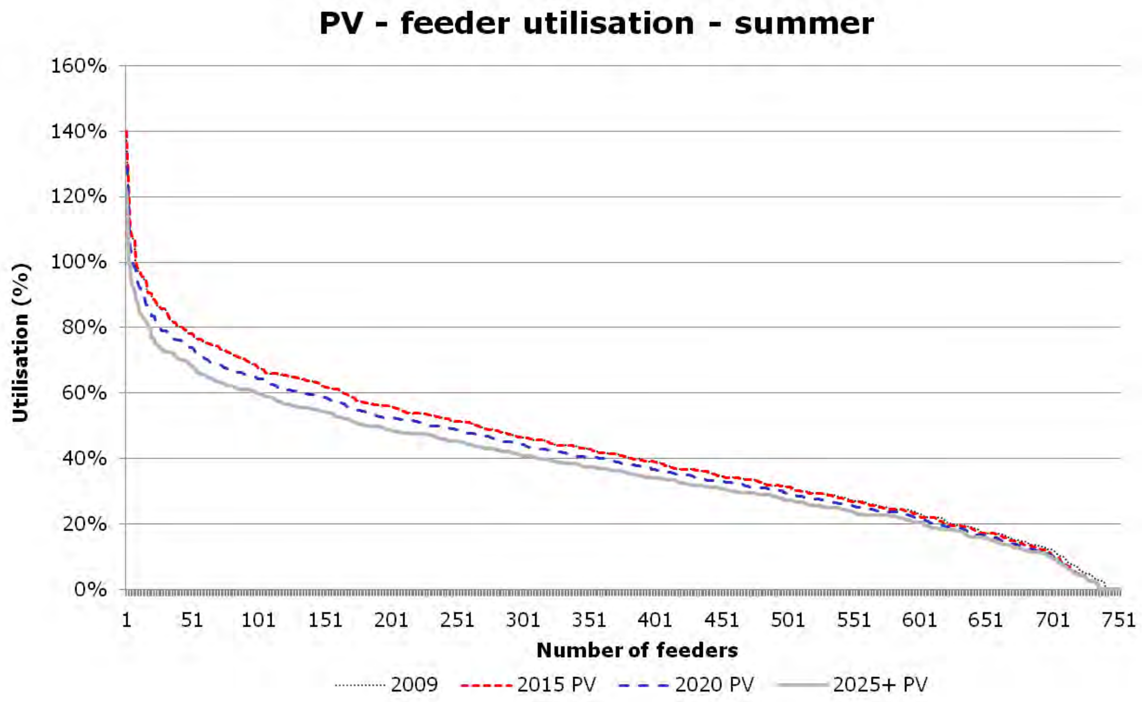


Figure 3-3 : Expected changes to feeder asset utilisation

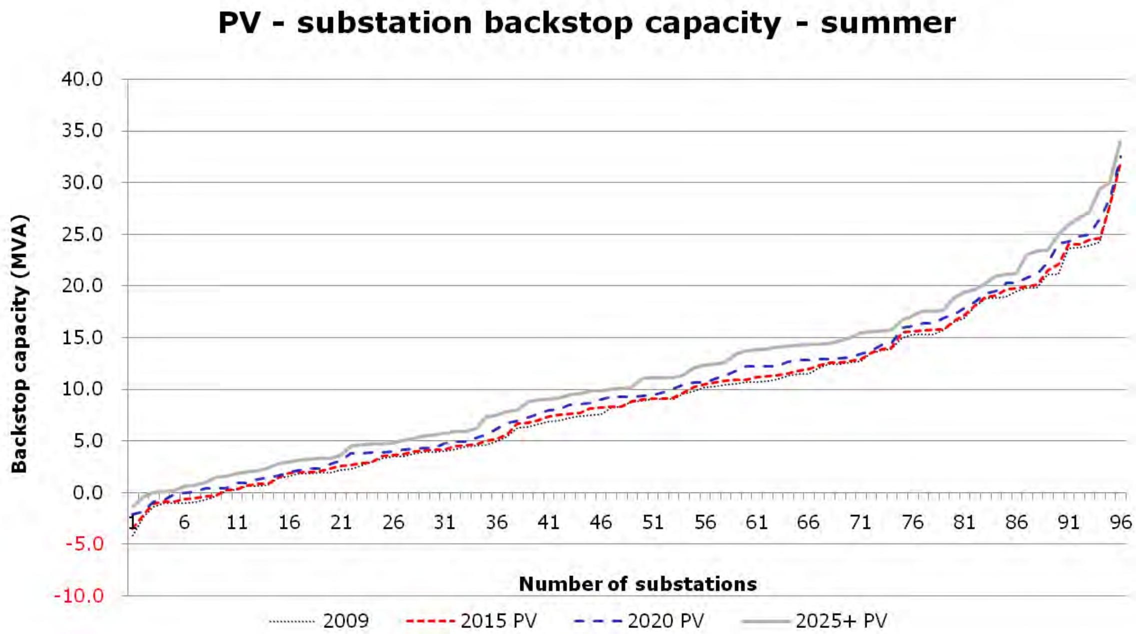


Figure 3-4 : Impacts on zone substation backstop capacities due to PV installation

A further outcome anticipated from the installation of large PV generation plants or the development of new subdivisions where PV is installed on all homes is the requirement to address potential over voltages or reverse power flows during times of light load and high generation (for example during sunny days in January).

3.2.2.2 Electric Vehicles

Leading vehicle manufacturers are planning to launch battery electric vehicles (EVs) commercially during 2012 in Japan, Europe and the USA. It is expected that customers will initially be concerned with some practical aspects of EV usage such as range, recharging method, maintenance facilities, etc., but once established sales are expected to accelerate. The impact of EVs on the network will be dependent on both take-up rate and charging patterns.

Vector estimated EV uptake in Auckland based on:

- Projections of vehicle growth in New Zealand compiled by the Ministry of Transport;
- Projection of EV growth in New Zealand compiled by the Electricity Commission;
- The assumption that the EV fleet will grow from new car purchases starting in 2013 and from used imports starting in 2016;
- Current vehicle sales and import data;
- EV manufacturers will target the small vehicle market; and
- The assumption of an exponential growth rate to reach a plateau of 50% of annual small vehicle sales within ten years of launch (a Canadian analysis concluded this percentage).

Based on the above, the number of EVs in New Zealand in 30 years may be around 500,000. The Electricity Commission predicts a similar EV fleet size in this timeframe. Germany has announced a target of having one million EVs by 2020 (i.e. one in 40 vehicles). Our projected penetration rate is similar. On the basis that Auckland's vehicle population is about 40% of the nation's, Figure 3-5 shows the estimated EV uptake for Auckland.

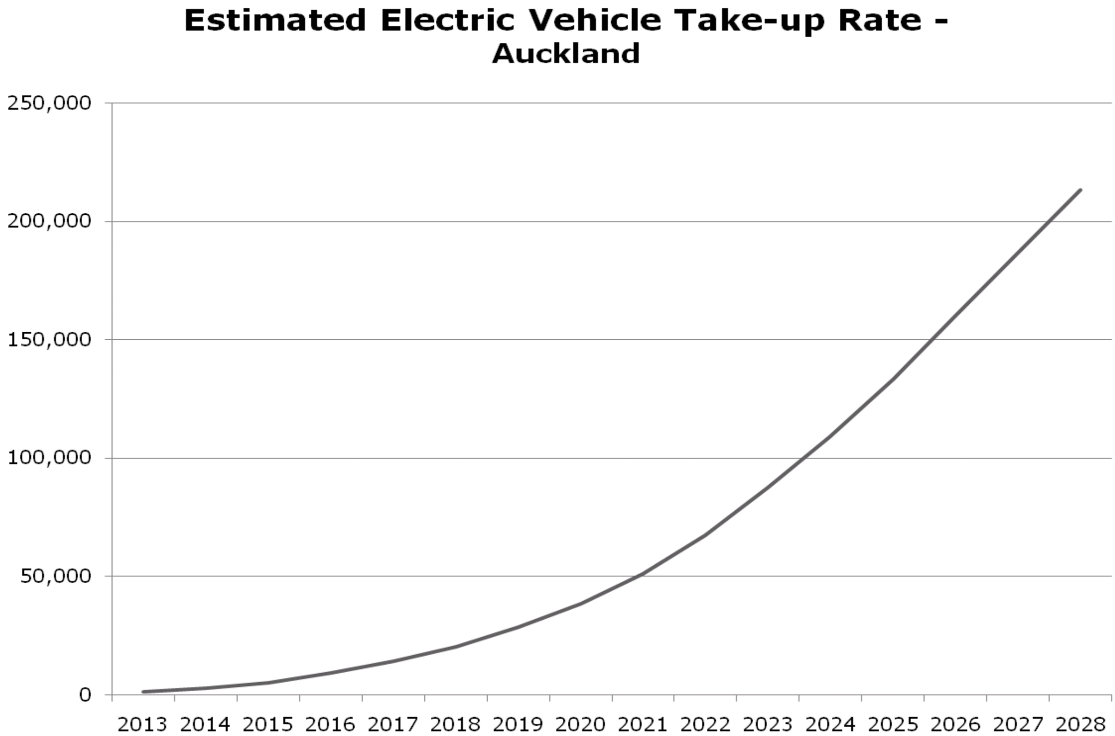


Figure 3-5 : Estimated electric vehicle take-up rate – Auckland

There are a number of potential charging methods for EVs, but research shows that at present there is no clear direction (anywhere in the world) on the likely mix. The various charging options will heavily influence the charging pattern, and hence have differing impacts on the demand on the electricity network:

- Battery swap out;
- Public charging stations; and
- On-premises charging.

An EV battery pack (based on current available vehicle models) will typically store approximately 24kWh of energy. This battery will offer a range of about 160km. Assuming an average daily use of 40km, each vehicle will require approximately 6kWh of charging each day. The total network load would rise by about 400MW (20% higher than at present), if this charging was carried out at home during peak electricity consumption times[20].

For the purpose of assessing the impact on network peak demand, a likely charging pattern was assumed – with Figure 3-6 and Figure 3-7 showing the likely effect of EVs on feeder utilisation and zone substation security.

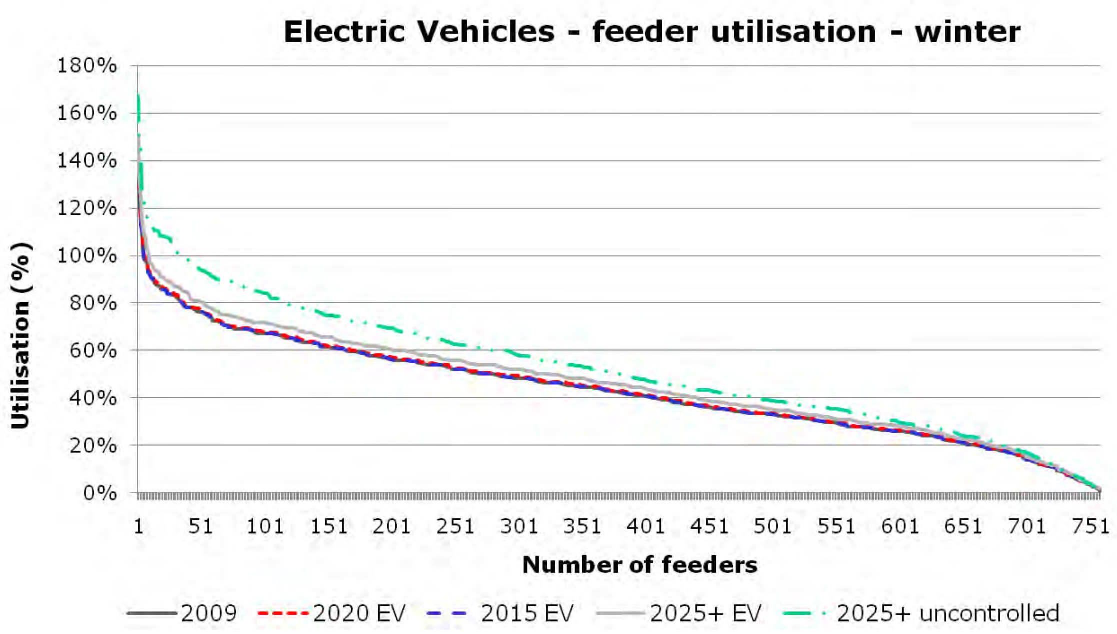


Figure 3-6 : Electric vehicles feeder utilisation – winter

[20] A further complicating factor is that it is also expected that as EV uptake increases the distortion on the power signal (harmonic level) will increase. This may require special control measures.

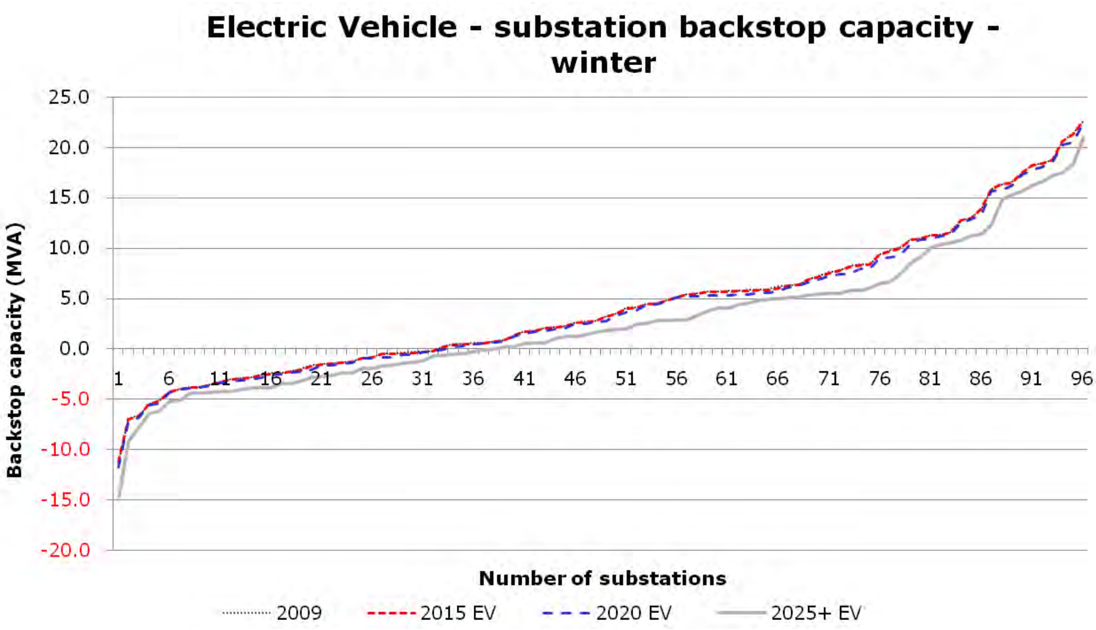


Figure 3-7 : Electric vehicle substation backstop capacity – winter

Based on the above scenario, there will be an increase in feeder utilisation, but this may not require serious attention before 2020. The additional load from EVs will also impact on network security, as the higher loading will reduce the backstop capability at zone substations.

3.2.2.3 Heat Pumps

Heat pumps are becoming a popular method of space heating, as prices reduce to affordable levels (and government subsidies encourage more efficient heating). This is changing both winter and summer energy usage patterns. A BRANZ report developed a projection of the penetration rates of heat pumps and predicted the impact on summer and winter demand and energy use. Heat pump installation is expected to reach 50% penetration in existing homes by 2020 (current penetration rate in Auckland is around 10%).

As heat pumps replace resistive element electric heaters, it is anticipated that there will initially be a fall in winter peak demand for heating due to the higher efficiency of heat pumps. However, demand is predicted to increase again as home owners gradually increase home comfort levels (temperatures and duration of use). This trend has been noticed in several countries where heat pumps are now widely used in homes.

While heat pumps are initially installed to provide efficient winter heating, they are predicted to be used increasingly for cooling on hot and humid summer days, resulting in a significant increase in summer peak demand and energy use. Figure 3-8 shows the summer and winter demand projection over the next 15 to 20 years.

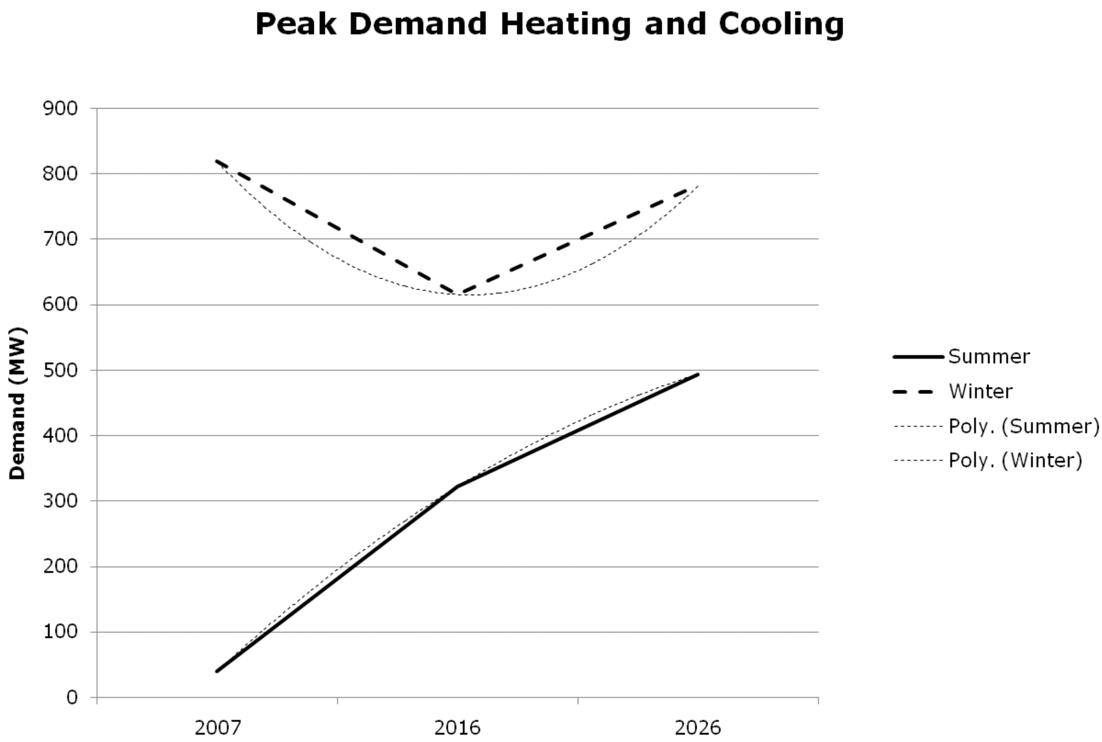


Figure 3-8 : Projected space heating and cooling peak demand on the Vector network

The expected increase in summer peak demand will likely result in a significant increase in feeder utilisation, coinciding with the time when feeder capacity is at a minimum. The additional load from heat pumps will also impact on network security, as the higher loading will reduce the backstop capability at zone substations. The effect on asset utilisation and backstop capacity is demonstrated in Figure 3-9 and Figure 3-10.

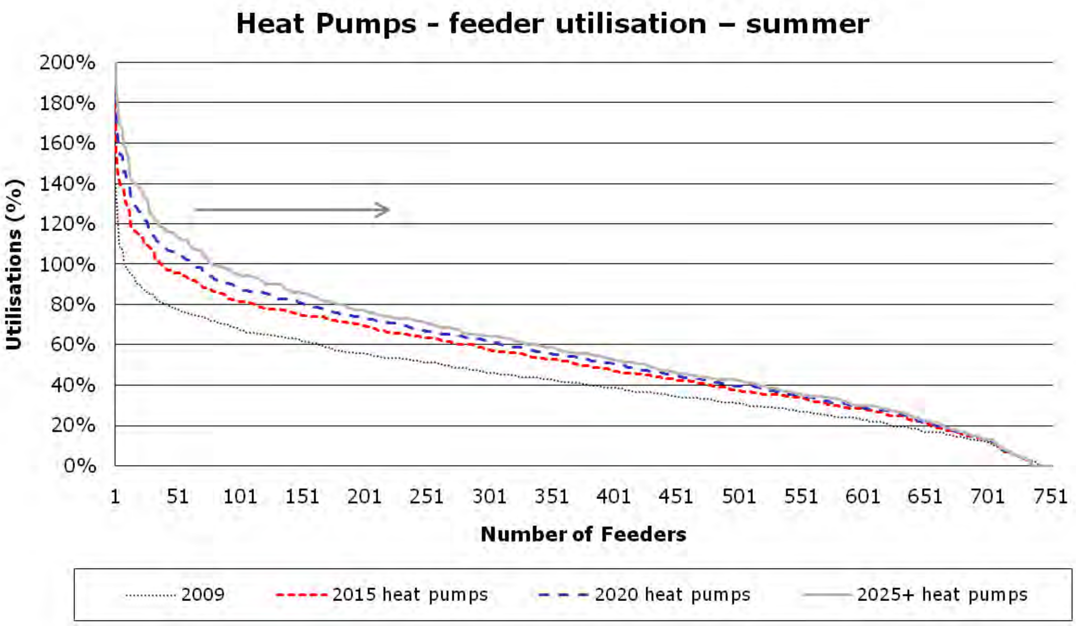


Figure 3-9 : Forecast effect of heat pumps on summer asset utilisation

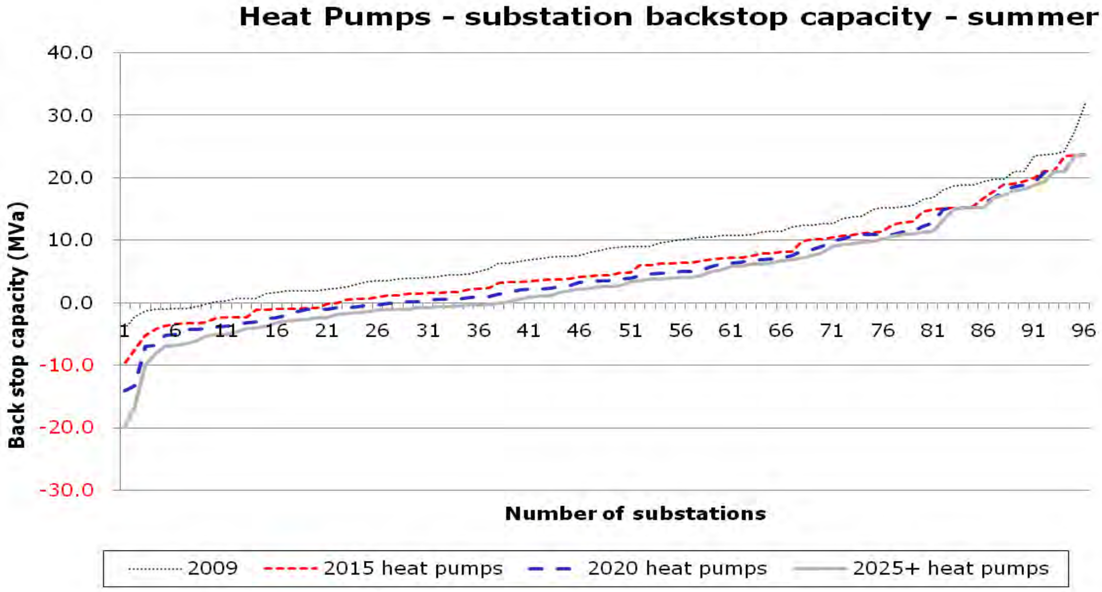


Figure 3-10 : Forecast effect of heat pumps on summer backstop capacity

In addition to the network capacity issues, a large penetration rate of heat pumps and a large number of heat pump motors running simultaneously may create further network issues, including:

- High starting currents may cause voltage dips, particularly in rural and remote areas;
- Decreasing power factor on the Vector distribution network;
- Instability problems on the transmission grid supplying the Auckland region;
- Low voltage (LV) problems; and
- Increase line losses.

There is generally a higher than average take-up rate of heat pumps in newly constructed houses. This needs to be allowed for in new subdivision design standards. The impact on feeders and zone substations may therefore be higher in areas with more new development, and possibly higher socio-economic areas.

Heat pumps for cooling are likely to only be used for a few days of the year when temperatures are high, creating peaks (kW) for a short period of time. While this will impact on network peak utilisation and may require material capacity augmentation, under current tariff systems (generally consumption based) this additional consumption is unlikely to be reflected in proportionally increased revenue.

3.2.2.4 Smart Home Technologies

Overseas observation indicates that smart meters, smart appliances and home energy management systems will change both energy consumption and peak demand patterns. A number of studies have been conducted which seek to quantify the potential savings associated with smart meters. The following are "typical estimates" from these studies:

- Energy savings through behavioural change from awareness and information could be up to 3%; and
- Peak demand reduction, driven by "time of use" pricing, could be up to 5%.

The above are based on "manual" actions taken by consumers to achieve the savings. When smart appliances and home energy management tools become available and affordable, these savings will likely increase (both from automated responses to price signals and improved energy efficiency of the appliances). To assess the potential impact of these devices on the network, an annual increase in projected savings was assumed from 2015 on, up to an eventual 5% energy savings and 7.5% peak load reduction. (These are the results achieved from a US-based trial project.) Allowing time for consumers to replace their existing appliances with "smart" units, it is assumed that the transition will occur over 15 years.

The introduction of smart meters, smart appliances, and home energy management systems is likely to decrease average feeder utilisation. Figure 3-11 shows the projected changes in feeder utilisation due to smart home technologies.

Smart meters or other intelligent devices also have a potential role to play as network measurement and control devices. For example, smart meters installed at distribution substations could provide detailed in-time LV network loadings, which in turn could be used for automated switching, network configuration control, or to adapt design standards.

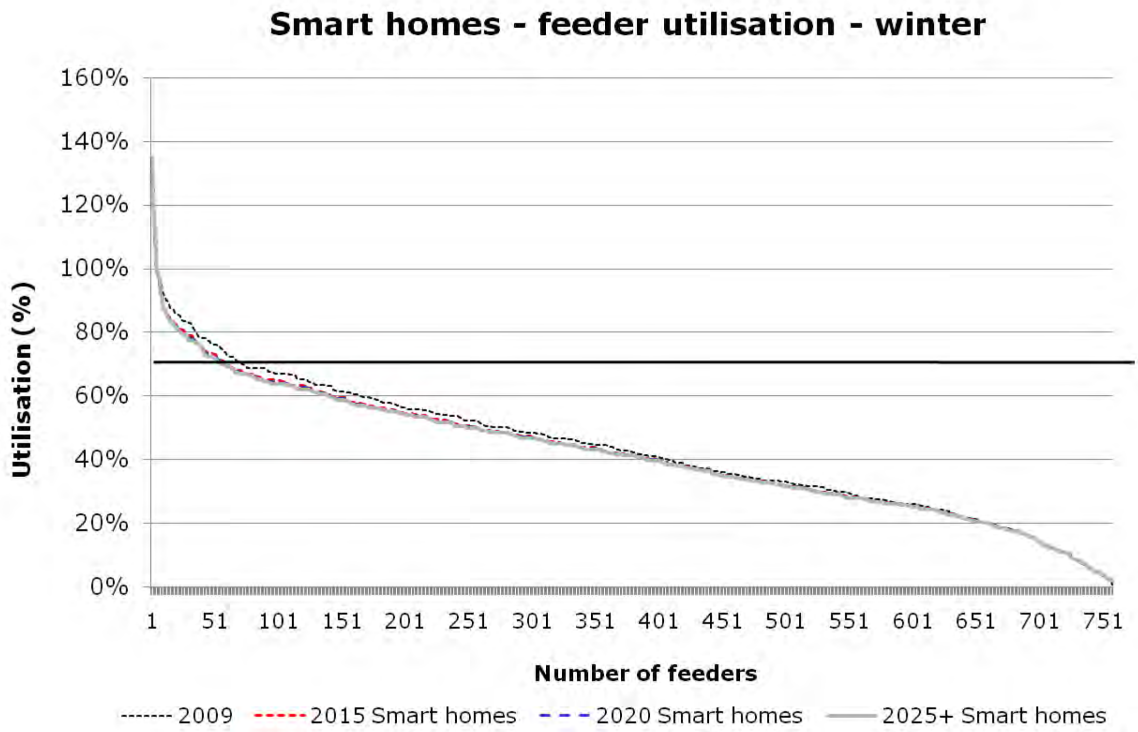


Figure 3-11 : Anticipated impact of smart meters on Vector's feeder utilisation

3.2.2.5 Overall Impact

If the penetration rate of the four technologies discussed above materialise as predicted, the effect on feeder utilisation will be as indicated in Figure 3-12 and Figure 3-13.

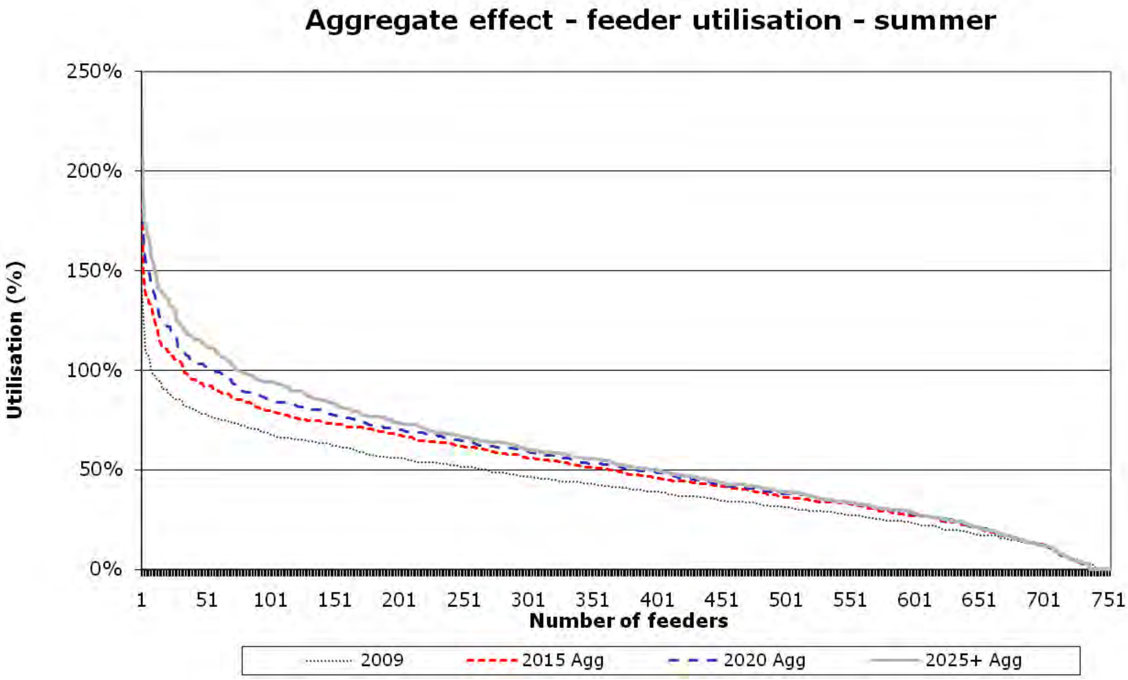


Figure 3-12 : Summer aggregate effect of emerging technologies on feeder utilisation

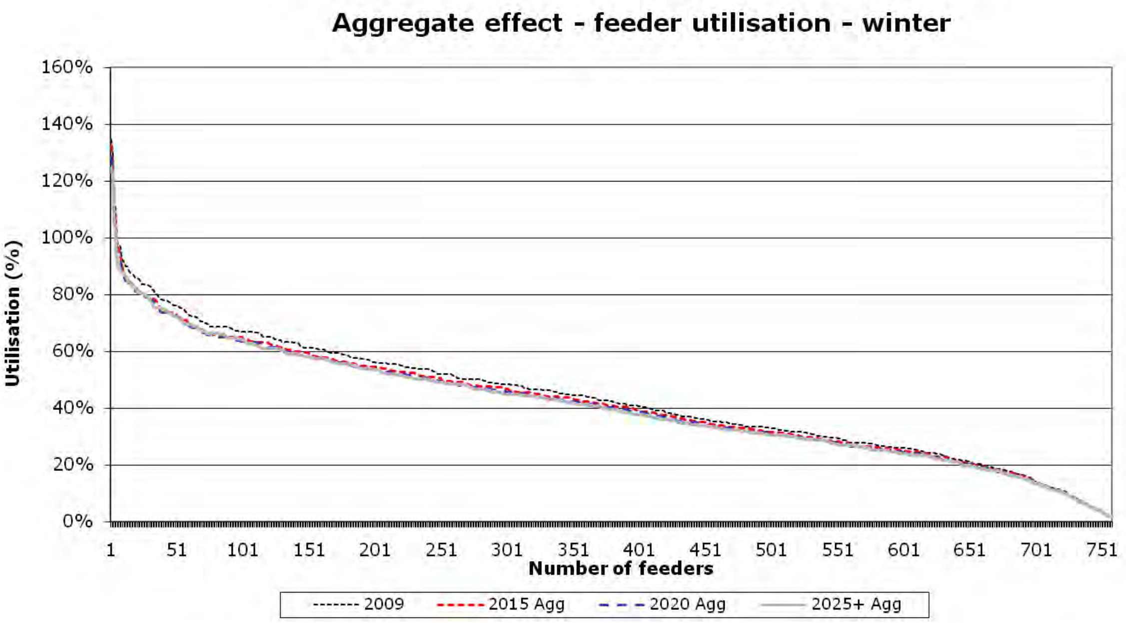


Figure 3-13 : Winter aggregate effect of emerging technologies on feeder utilisation

These anticipated trends have been incorporated into our network planning assumptions, as reflected in this AMP.

3.2.3 Action Plan – Preparing for Future Technologies

Vector is in the process of developing a range of strategies to deal with anticipated changes in future technology and electricity consumption patterns, including the required expansion of our information management infrastructure.

Aspects that will be covered under these strategies include:

- Demand and energy management;
- Distributed generation;
- Smart meters and home management hubs;
- Energy substitution; and
- Smart distribution networks.

Flowing from work done to date in these areas, we have already identified a number of areas where Vector will keep a watchful brief, ensuring that the company is well-prepared to deal with the changing environment. Key aspects being monitored include:

- Uptake of heat pumps, using industry statistics on installations;
- Summer peaks on residential feeders to check for signs of heat pump use on hot days (annual action);
- International developments of:
  - Electric vehicle and battery technologies;
  - Availability of EVs; and
  - Charging infrastructures.
- Price trends of solar PV;
- Impact of smart meters/time-of-use pricing on residential feeders;
- Developments of home energy management systems, the role of smart meters and the development of smart appliances; and
- Fuel cell and battery storage developments.

3.3 Smart Network Applications

As described above, Vector is developing strategies to deal with emerging technology. One area that has already been identified as potentially critical is the emergence of smart networks.

Technology developments are making it possible to significantly increase the levels of "intelligence" on the electricity network. Increased network monitoring, automated switching and intelligent control systems offer major opportunities for improved asset management, more efficient capital investment and improved customer service.

Vector is embarking on a set of trials of various smart network applications during the course of 2010.

Figure 3-14 shows Vector's strategic goals for smart network applications and the potential benefits that can achieved through the roll-out of a smart network.

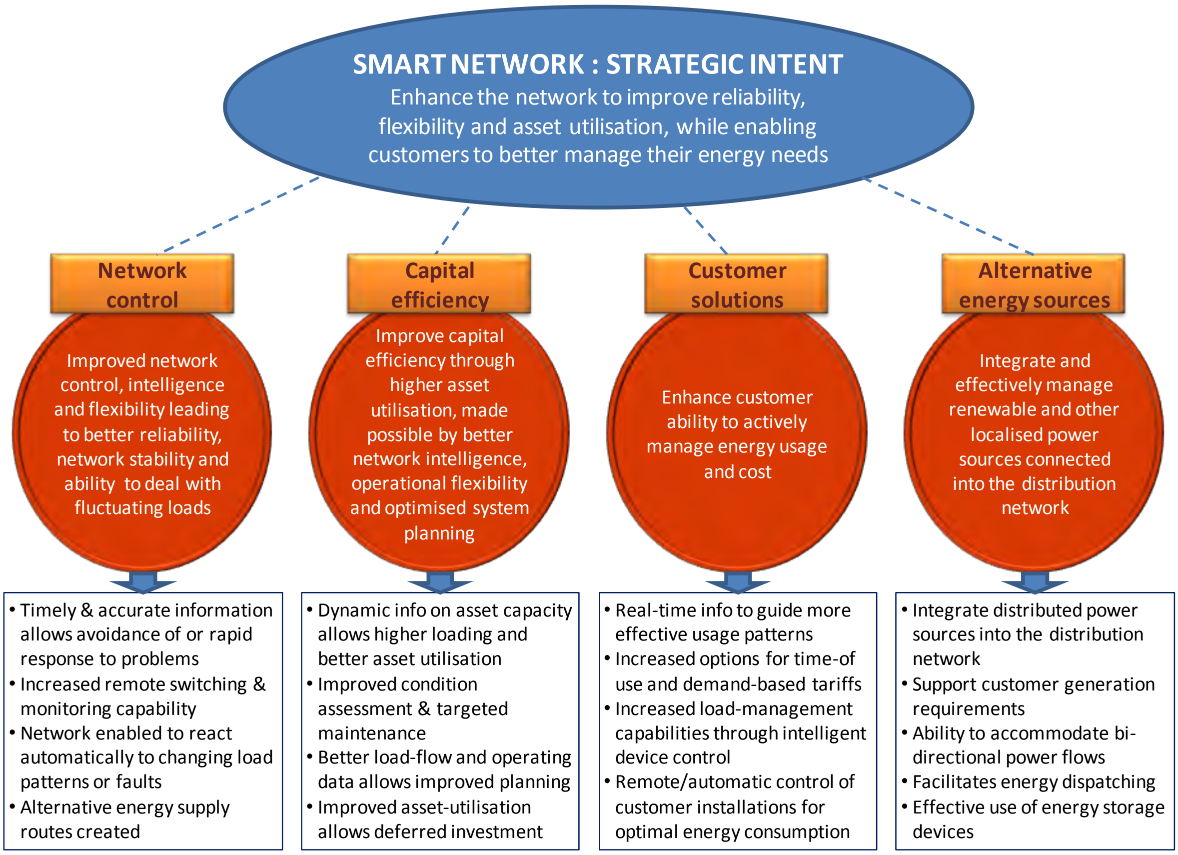


Figure 3-14 : Vector's vision for smart network applications

The purpose of Vector's smart network trials is to:

- Test ideas and equipment in practical network situations (to see what works well in the Vector network environment);
- Develop the required supporting infrastructure to effectively manage high volumes of data from intelligent devices;
- Guide our theoretical research;
- Help us understand what is being done elsewhere, what is available and what opportunities exist; and
- Depending on the outcome of the trials, help us define a potential next roll-out phase and basis or otherwise for a robust business case.

The outline of the initial trials is given in Figure 3-15.

In future further trials and equipment roll-outs may be undertaken subject to business case. However, the nature, extent and cost of this will be informed by the initial trials and no further work is therefore included in the planning period for the current AMP.

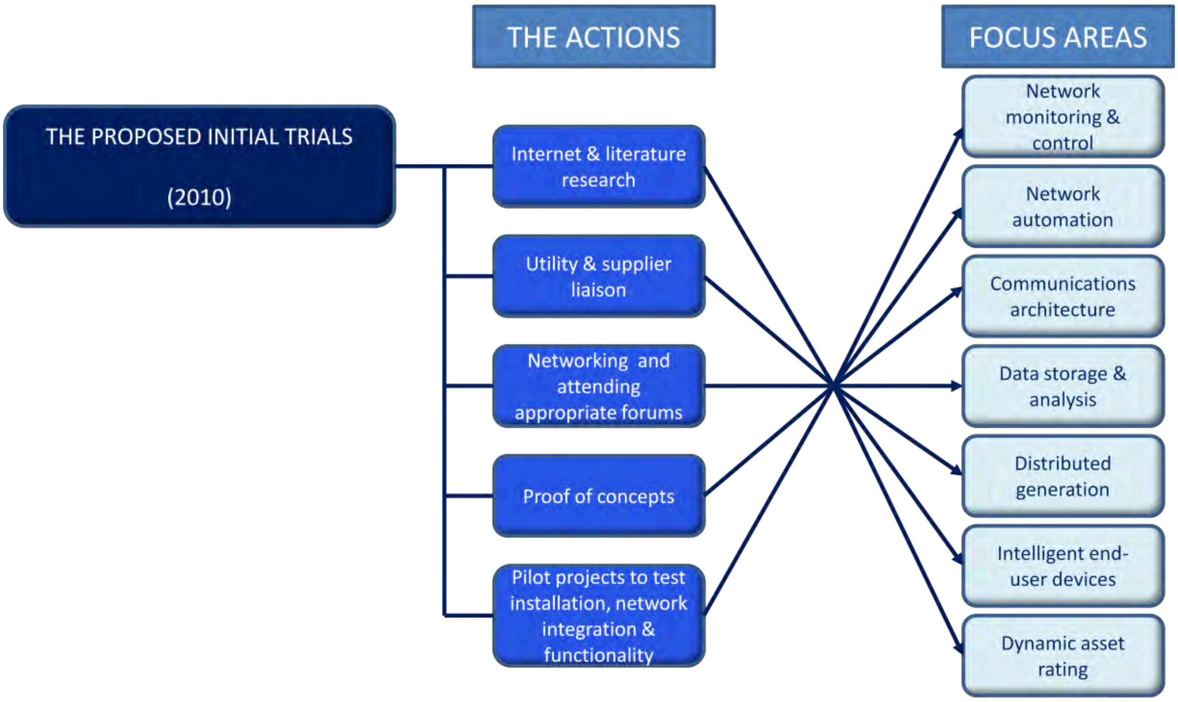


Figure 3-15 : Outline of Vector's smart network trials for 2010

4. Service Levels

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

Following commissioning of a Technical Asset Master system (see Section 6 and Section 7 for further discussion on these), Vector will be 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 AMPs.

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 us to meet this goal with the optimum investment. As such we recognise that 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 feed back 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 our bi-annual consumer surveys. The results of these surveys provide a basis for setting our customer service levels, by drawing out customer preferences around the reliability of supply in terms of outages and duration of outages, and the extent to which customers would be prepared to pay for improved reliability.

Results from the 2006 and 2008 surveys are summarised in the following table. Both surveys were undertaken by computer assisted telephone interviewing (CATI). Participants were identified as the "person most responsible for making decisions relating to electricity".

Customer Survey Date	Mar 2006		Jan 2008	
Residential category	Urban	Rural	Urban	Rural
Sample size	1183	958	829	671
Satisfied with the value for money regarding their electricity supply	81%	70%	79%	70%
Rate the current service provided by Vector as adequate or better	84%	74%	91%	79%
Believe they have experienced less than 3 outages over 12 months	74%	37%	74%	32%
Believe they have experienced less than 6 outages over 12 months	92%	68%	89%	61%
Rate the frequency of outages experienced to be acceptable	77%	58%	71%	50%
Do not wish to pay an additional amount for fewer outages	79%	85%	85%	82%
Do not wish to pay an additional amount for NO outages	82%	84%	84%	85%
Consider a maximum of 3 outages per annum to be acceptable	76%	76%	81%	72%
Believe the last outage they experienced was less than 3 hours	55%	67%	58%	48%
Believe the last outage they experienced was more than 3 hours	10%	16%	23%	33%
Rate the duration of the last outage experienced to be acceptable	68%	49%	63%	49%
Do not wish to pay an additional amount for shorter duration outages	85%	87%	90%	89%
Consider a 30 to 60 minute outage to be acceptable	43%	30%	56%	61%

Table 4-1 : Summary of 2006 and 2008 survey results

In summary the feedback received from the most recent engagement survey continues to validate the following general preferences:

- Most 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
- Most customers express no desire to pay an additional amount to receive a service with reduced number of outages or reduced duration of outages.

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

In addition to the bi-annual surveys, Vector's larger scale engagements tend to focus on councils and community groups.

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).

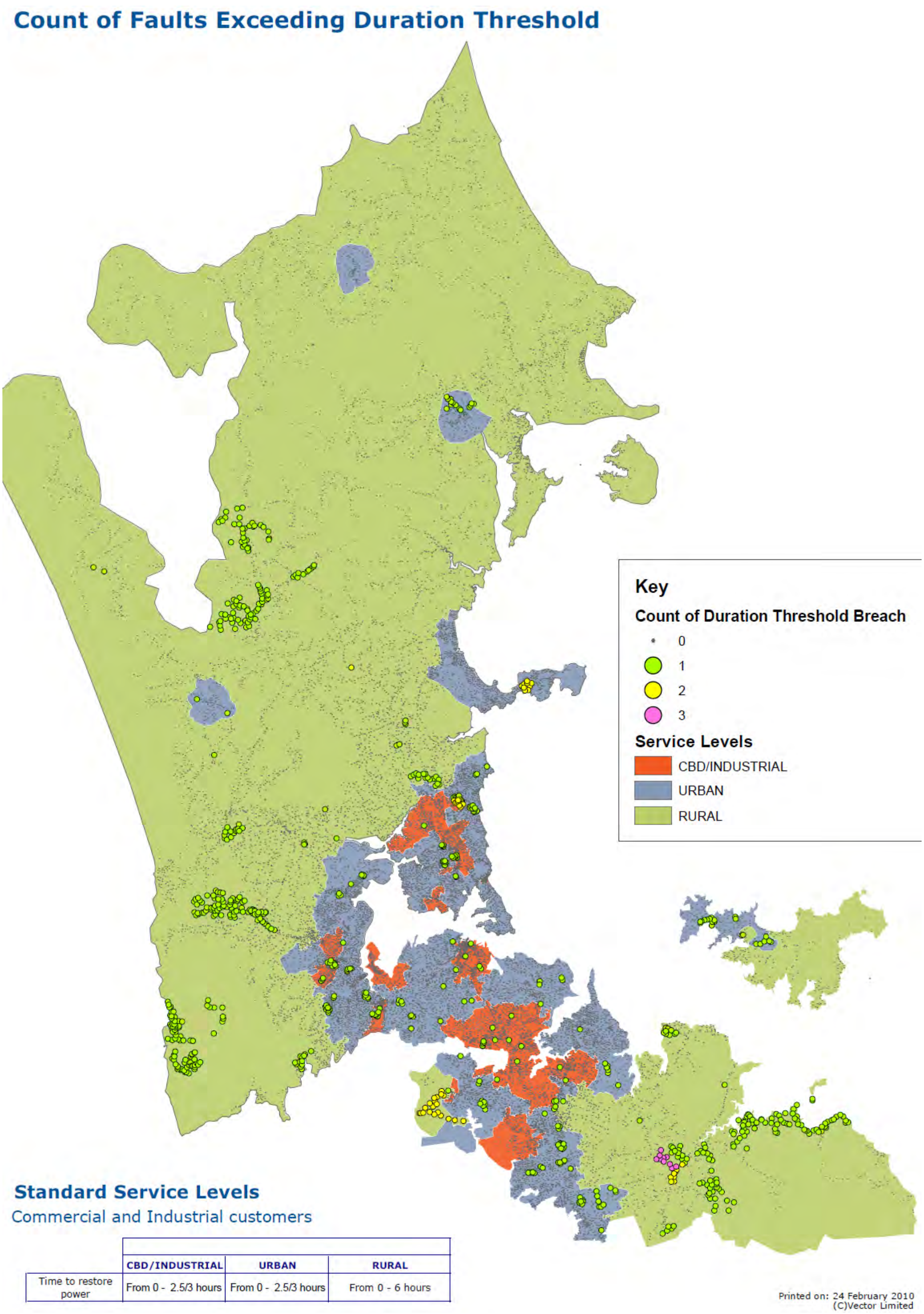
The service standards are specific to the customer/retailer relationship model adopted on the various parts of our network, as indicated in table below.

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

Note that incidents arising as a result of bulk supply failures – generation or transmission – 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 six months to end of February 2010. Figure 4-2 shows performance against outage frequency thresholds based on the same period.



	CBD/INDUSTRIAL	URBAN	RURAL
Time to restore power	From 0 - 2.5/3 hours	From 0 - 2.5/3 hours	From 0 - 6 hours

Figure 4-1 : Count of faults exceeding duration threshold

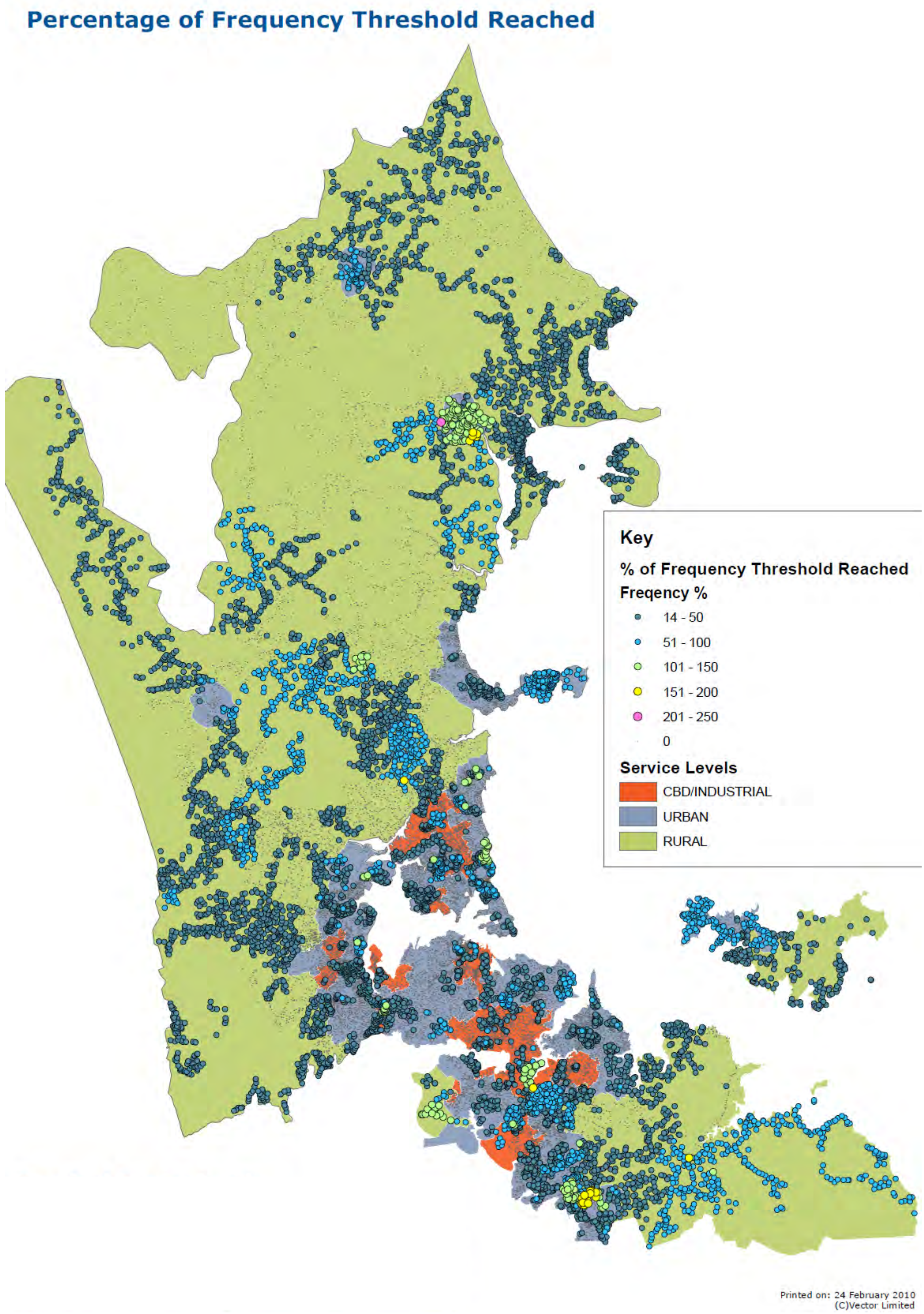


Figure 4-2 : Count of faults exceeding frequency threshold

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 KPI purposes; and
- Satisfaction with Vector's Field Service Providers' (FSP's) 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 Target
Targets for the Contracting Partners and Call Centre are 85% whilst the target for the Vector overall score is currently 83%.

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.

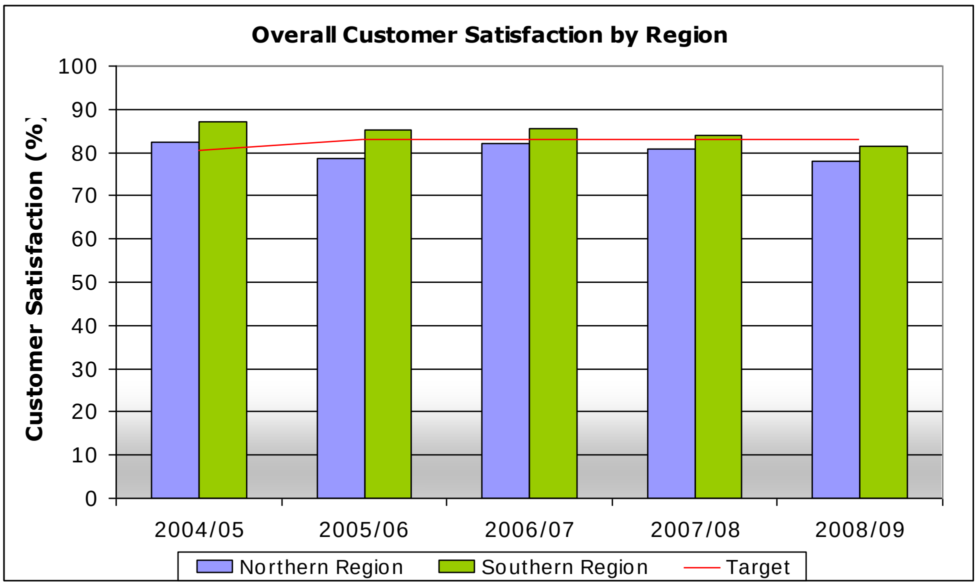


Figure 4-3 : Overall customer satisfaction

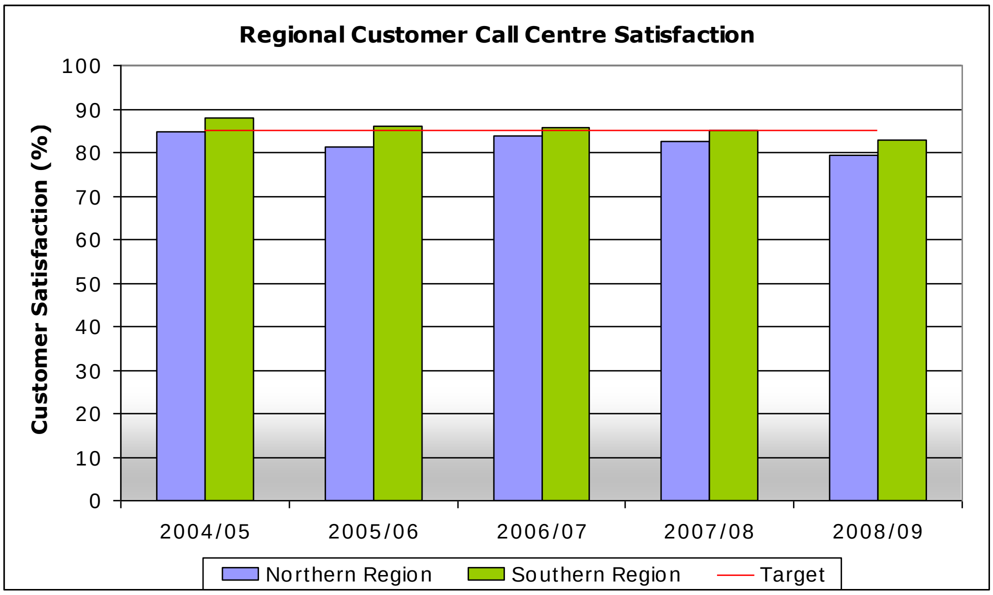


Figure 4-4 : Customer call centre satisfaction

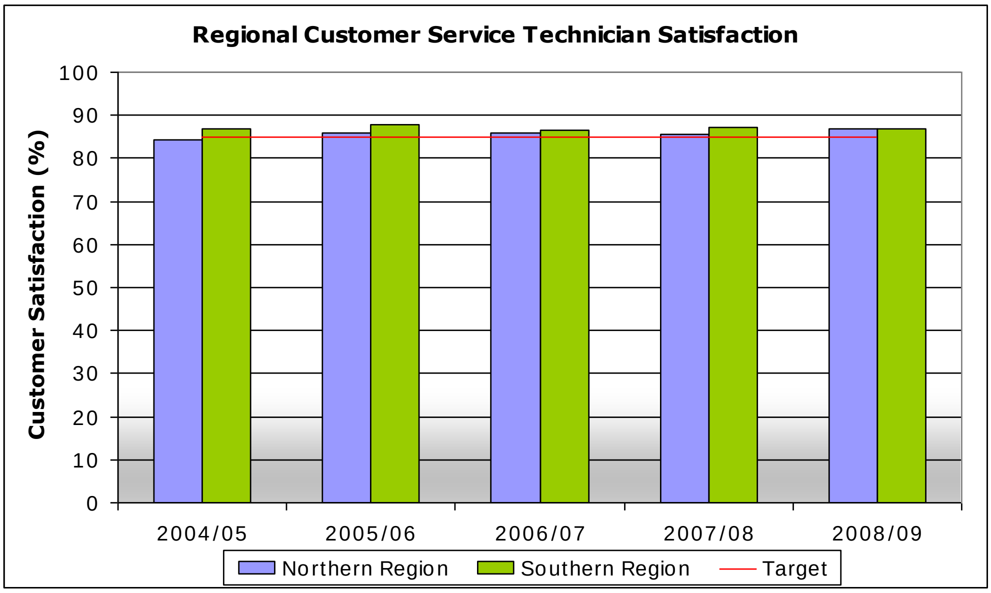


Figure 4-5 : Customer service technician satisfaction

Note that Vector continues with two different business models for customer interaction based on existing contractual 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.

Customer satisfaction is better where there is direct contact.

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 our 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, where appropriate and reasonable.

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 attending community meetings, meeting 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;
- Providing the customer with an update and/or working to resolve the complaint; and
- If the complaint is not resolved within the stated timeframe, informing the customer of the reason for the delay and working towards resolution.

If we have not resolved the complaint within the timeframes specified by the Electricity and Gas Complaints Commission (EGCC, see below) then the customer has 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 prescribe timeframes. 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 key performance indicator (KPI) programme.

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

For the 2008/09 year 1,763 customer complaints were received, of which 1,670 (95%) were resolved in time.

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 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 the 2008/09 year, 42 (2.4%) complaints went to the EGCC, of which 35 were resolved under Vector's standard resolution process.

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

- Two were resolved by settlement;
- One was not pursued by the customer;
- Two went to Notice of Intention (neither was upheld); and
- Two went to Recommendation (neither 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. Note that the poor Faults Line performance in July 2008 corresponds with an extreme weather event late in that month. Following this event, Vector took steps to improve its customer service, including:

- Providing an improved telephone messaging service for customers;
- Publishing better and more up to date outage information on Vector's website; and
- Use of social media such as Twitter.

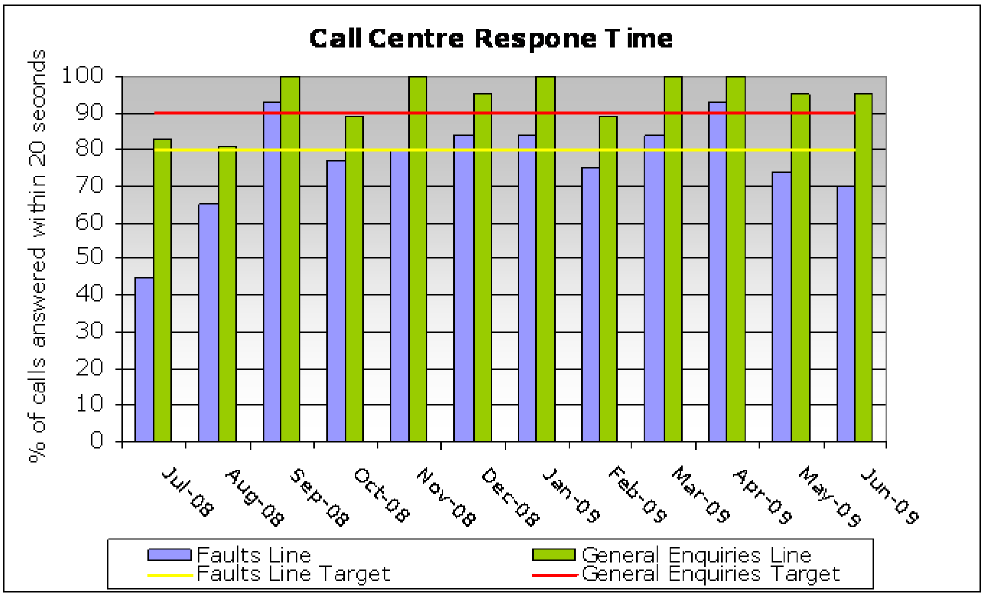


Figure 4-6 : Call centre response time

4.1.5 Supply Quality Standards

Vector's supply quality objectives are focused on ensuring that the required service levels are achieved and maintained in accordance with its published customer expectations and 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 230 V)	± 6%
Voltage at point of supply (three phase 400 V)	± 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 that is 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 53 Power Quality Monitors (PQMs) located at zone substations covering Auckland CBD, industrial, urban and rural locations (plus four mobile units).

The following table provides a summary of compliance to the published service standards disaggregated by various customer locations.

Zone Sub	Location	03/04	04/05	05/06	06/07	07/08	08/09	Target
Quay	CBD	6	17	6	26	11	29	≤20
Victoria	CBD	18	13	8	16	9	6	≤20
Carbine	Industrial	-	6	6	18	7	10	≤20
Rockfield	Industrial	-	8	11	13	4	12	≤20
Rosebank	Industrial	-	10	8	17	14	13	≤20
Wiri	Industrial	26	10	20	15	13	18	≤20
Bairds	Urban	18	17	20	39	25	27	≤30
Howick	Urban	10	6	22	22	12	20	≤30
Manurewa	Urban	24	15	15	23	33	22	≤30
Otara	Rural	9	8	35	25	17	17	≤40
Takanini	Rural	33	22	25	26	28	23	≤40

Table 4-2 : Summary of compliance to the published service standards

Typical responses to non-compliance to service standards include targeted maintenance (such as vegetation control), network inspections (such as thermal and ultraviolet imaging to detect hot spots and weak links), asset renewal/replacement 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). The following table shows mean THD calculated as a percentage value on an hourly basis.

Zone Sub	Location	03/04	04/05	05/06	06/07	07/08	08/09	Target
Quay	CBD	1.1	1.3	1.5	1.6	1.6	0.7	≤5.0
Victoria	CBD	2.1	2.0	1.7	1.6	1.4	0.7	≤5.0
Carbine	Industrial	-	3.2	3.4	3.6	3.5	2.2	≤5.0
McNab	Industrial	1.0	1.0	0.9	1.1	1.6	0.9	≤5.0
Rockfield	Industrial	-	2.8	2.9	3.1	3.2	2.9	≤5.0
Rosebank	Industrial	-	3.2	3.1	3.5	3.3	2.0	≤5.0
Wiri	Industrial	1.7	1.9	2.0	2.2	2.1	1.2	≤5.0
Bairds	Urban	1.5	1.5	1.5	1.6	1.9	1.3	≤5.0
Howick	Urban	2.5	2.5	2.5	2.6	2.9	2.3	≤5.0
Manurewa	Urban	3.3	3.2	3.1	3.4	3.7	2.6	≤5.0
Otara	Rural	1.5	1.4	1.2	1.4	2.2	1.4	≤5.0
Takanini	Rural	2.7	2.7	2.7	2.6	2.7	1.7	≤5.0
Oratia	Rural						1.4	≤5.0
Hillcrest	Residential						2.1	≤5.0
East Coast Bays	Residential						2.5	≤5.0
McKinnon	Commercial						1.7	≤5.0

Table 4-3 : Mean THD calculated as a percentage value on an hourly basis

The decreases in THD at Rosebank and McNab, where capacitor banks have recently been out of operation, indicates a need for further investigation as potentially the capacitor banks are acting as harmonic "sinks" and may need to be de-tuned. The significant reductions in THD observed at other locations in the last year most likely indicate that a small number of large industrial loads reduced their usage or moved to another location where PQMs are not installed.

Our future objective is to have PQM coverage at all zone substations in order to gain a comprehensive understanding of the causes and impacts of power quality (PQ) issues. The necessary measuring devices will be progressively installed over 2011 and all new zone substations will be equipped with PQ meters.

4.1.6 Supply Reliability Performance

Our strategic goal is to ensure that 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 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 related events.

Vector Target

Disclosure Year	09/10	10/11	11/12	12/13	13/14	+5 yrs
SAIDI (Minutes)	104	127	127	127	127	127
SAIFI (Interruptions)	1.63	1.86	1.86	1.86	1.86	1.86

The step increases in SAIDI and SAIFI threshold targets from 2010/2011 reflect the reset regulatory regime from 1 April 2010.

Figure 4-7 below shows the comparison of SAIDI for the current regulatory year to date against the regulatory threshold expressed as a straight line target.

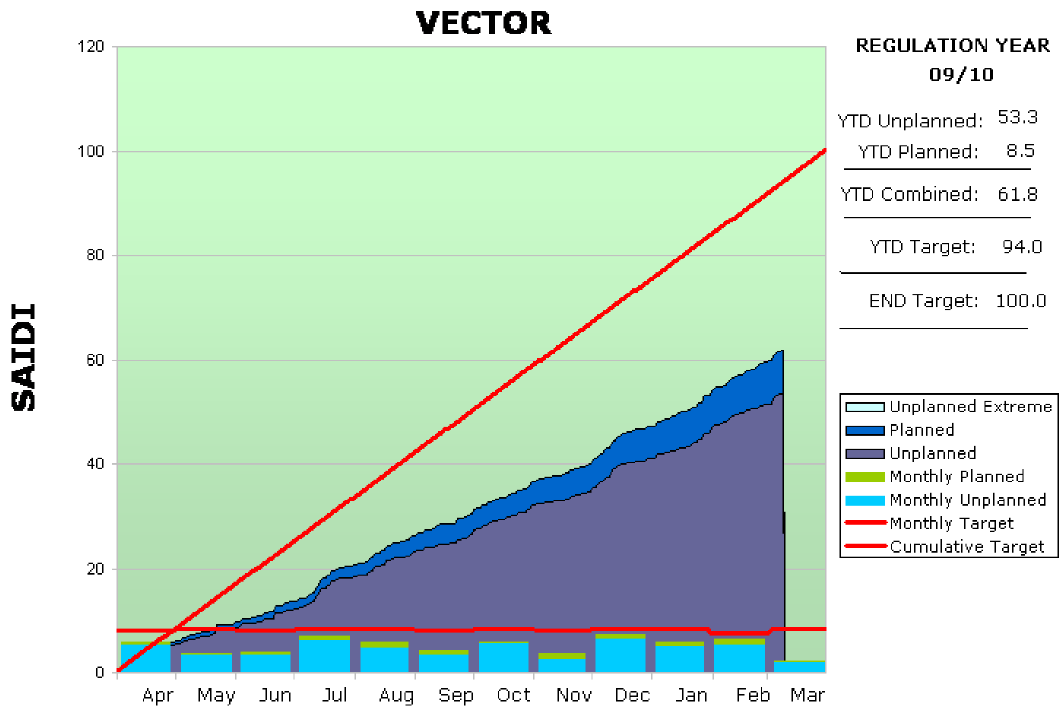


Figure 4-7 : Comparison of SAIDI against the regulatory threshold

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 chart 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.

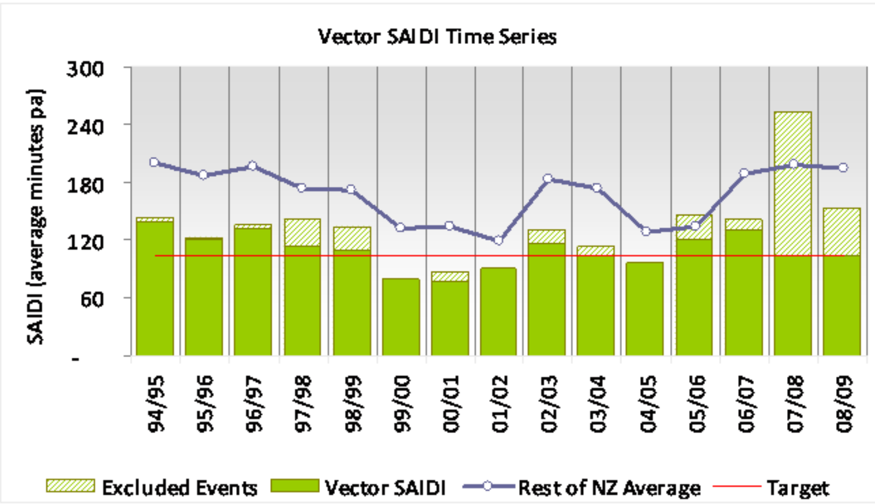


Figure 4-8 : Vector SAIDI time series

Vector 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 return filed for the 2008/09 regulatory year indicated significant network damage resulting from extreme weather impacting the network over 26 to 27 July 2008. Although not on the same scale as the storm of the previous year, this event was highly significant and incurred 57 SAIDI minutes. The overall year end network SAIDI finished at 153 minutes, including excluded events, against a target of 104 minutes.

Vector's SAIFI performance is presented below on the same basis. The return for the 2008/09 regulatory year of 1.68 exceeded the target of 1.63.

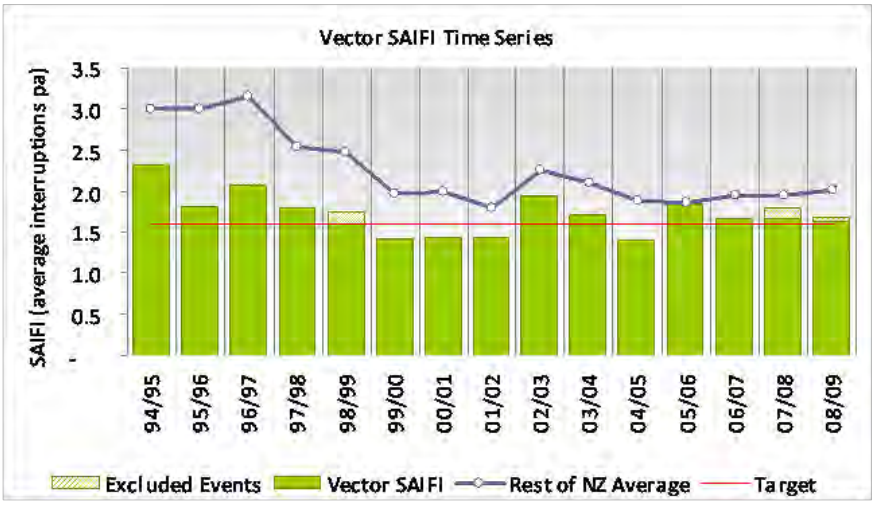


Figure 4-9 : Vector SAIFI time series

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.

The following chart shows how the impact of major causes of network interruptions has changed over the last 15 years. Each of these causes are considered in depth below.

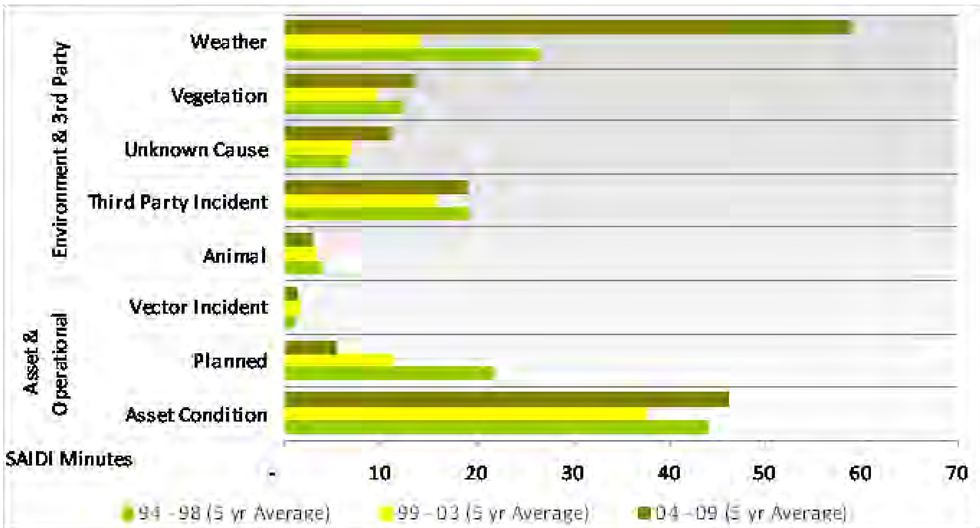


Figure 4-10 : Impact of major causes of network interruptions

- Weather – this includes events caused by lightning and wind, 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.
- 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. Tree regulations introduced a few years ago 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 are unworkable and is actively participating in an industry working group to review the regulations. Meanwhile, although not yet observable in the five-year average values displayed above, based on vegetation related faults for 2009 to date, an all time low, Vector's maintenance activities appear to be effective.
- 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 undergrounding 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 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. Although underground assets are extremely 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 average impact from planned shutdowns has reduced to around 25% of the level experienced a decade ago, largely as a result of live-line "glove and barrier" work practices and the increased use of back-up generation.

Overall at Vector, as shown in the following chart, the proportion of SAIDI associated with environmental and third party incidents has been increasing over time; conversely the impact of asset and operational interruptions has reduced.

Figure 4-11 : Proportion of SAIDI associated with environmental and third party incidents

4.1.6.3 Factors outside Vector's control

Overall, around 40% of 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 contacts with overhead lines).

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

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, reduced maintenance and asset replacement effort will, over time, result in increasing numbers of failures as the average age of the network increases, and the number of unresolved defects increases.

Approximately 60% of current faults are considered to be theoretically preventable, for example equipment failure, human error, 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.

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.

4.1.6.6 Reducing the Number of Customers Affected by a Fault

To reduce the impact of a network failure, the solution is essentially to break up the network into smaller chunks (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.

The two most cost effective technologies currently available are distribution automation and ground fault neutralisers. Network automation projects already implemented over the last three years at a cost of around $10 million are already saving around 30 SAIDI minutes per annum on an on-going basis, as described below.

4.1.6.7 SAIDI Avoided by Automated Protection Devices

Over the past three 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 $ 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 following plot is updated daily and available to all Vector staff on the company intranet.

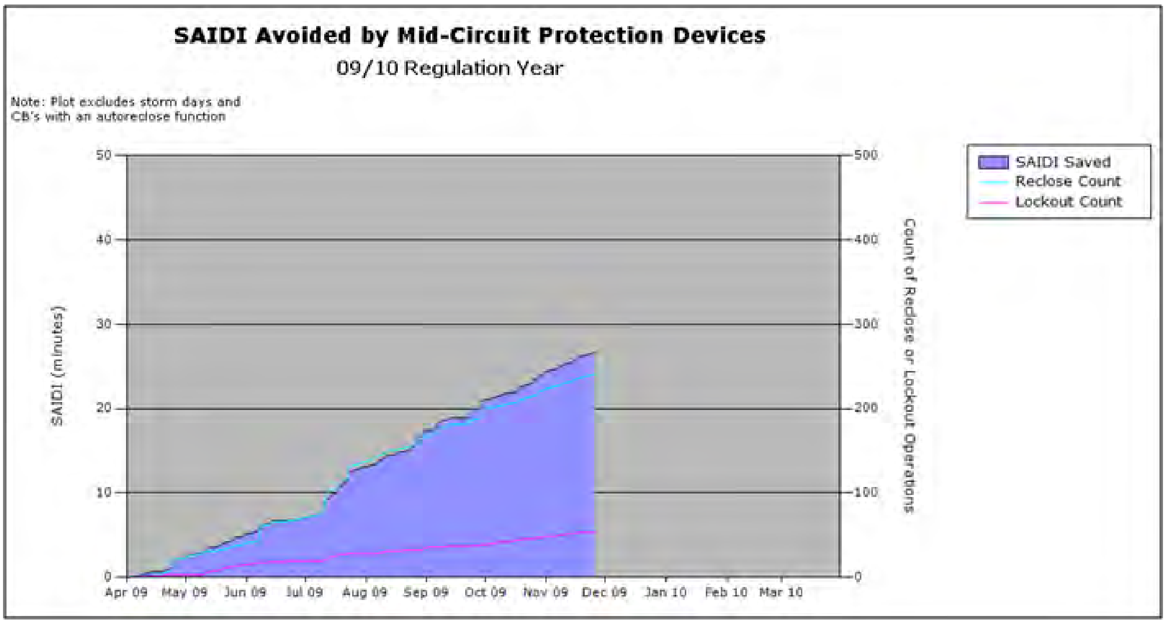


Figure 4-12 : SAIDI avoided by mid-circuit protection devices

The diagram below shows the historical SAIDI benefits derived over the course of the programme.

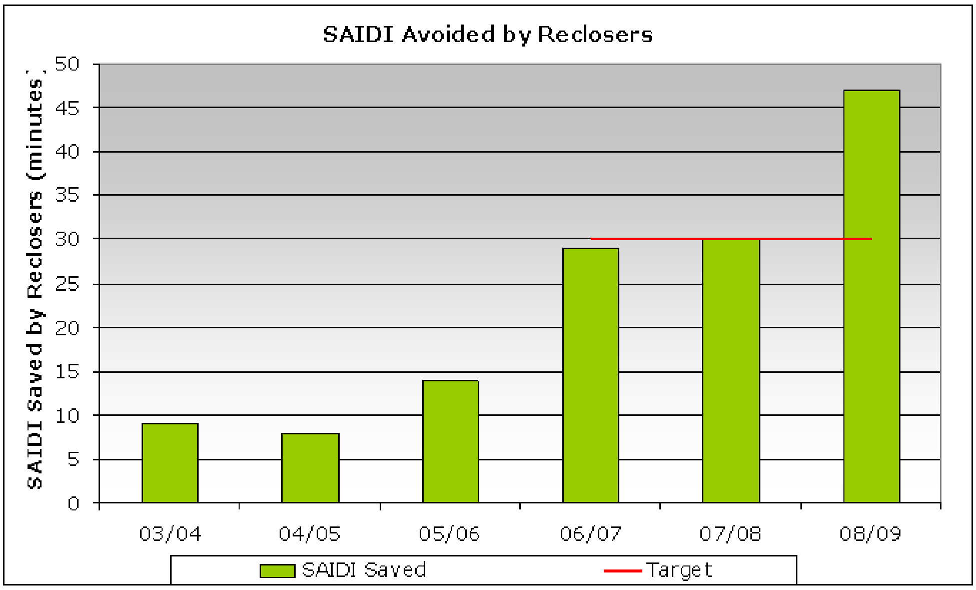


Figure 4-13 : SAIDI avoided by reclosers

4.1.7 Justification of Consumer Oriented Performance Targets

Supply reliability and response targets are normally established through taking into account consumer 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, 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 five years.

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.

4.2 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 HV distribution and sub-transmission sustained unplanned interruptions."

The failure rate in 97/98 was just over 12.5 faults per 100km, increasing to 18.5 faults per 100km for the 08/09 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 past four years has been significantly influenced by extreme weather events.

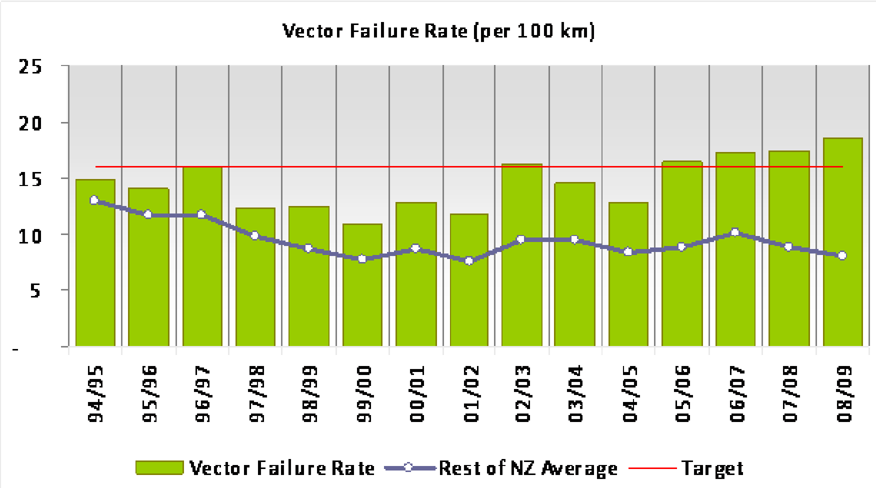


Figure 4-14 : Vector failure rate

Vector has investigated the apparent gap between its line failure rate and the average for the rest of New Zealand, but beyond a few obvious contributing factors, to date no compelling cause could be identified. The result contradicts 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 measurement methodology, but work is continuing to determine the root cause. Following that, a strategy will be developed to address any underlying asset performance and/or measurement methodology issues.

Vector's Network failure rate target is:

Vector Target

Disclosure Year	09/10	10/11	11/12	12/13	13/14	+ 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 the following chart.

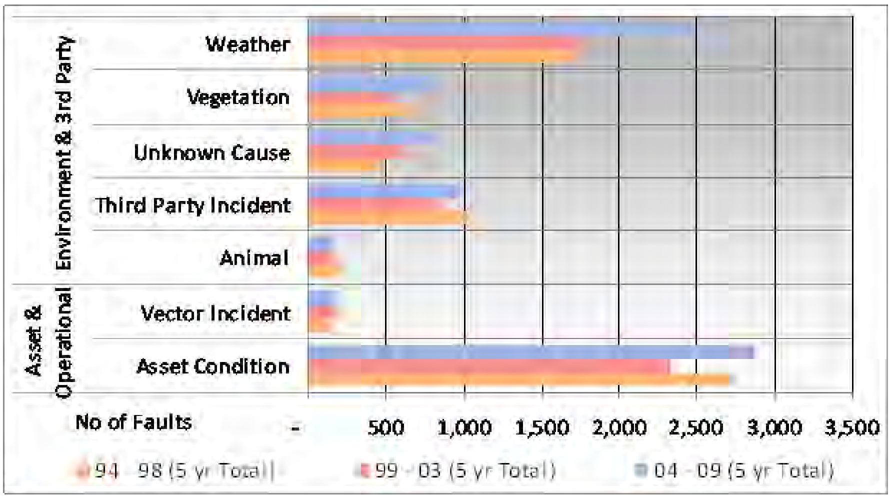


Figure 4-15 : Reasons for network failures

Note that 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:

- Faults due to Vector incidents - 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 4-16 below shows that these incidents remain relatively static at around 35 events per year, corresponding to a failure rate of 0.2/100km.

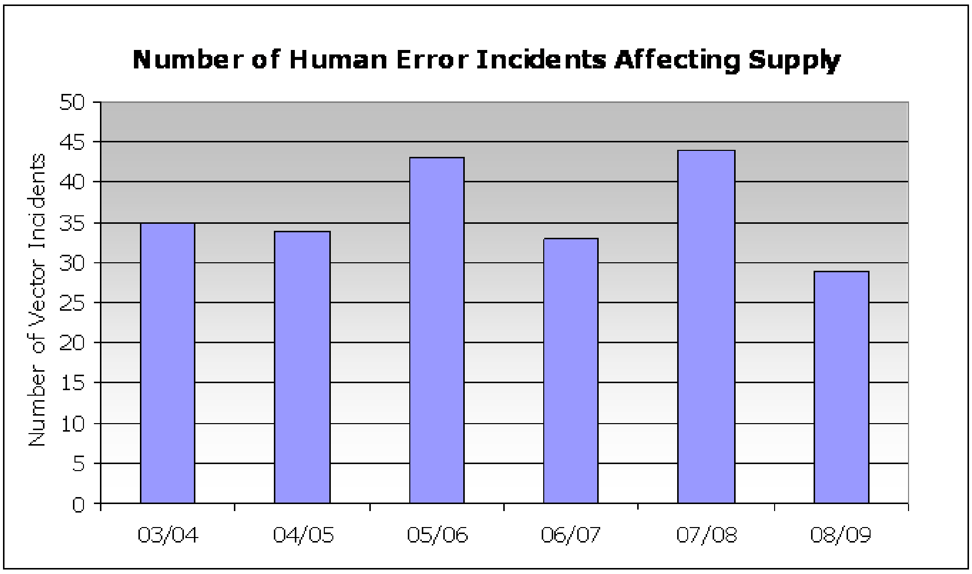


Figure 4-16 : Number of human error incidents affecting supply

This represents approximately 1% 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, and permanent corrective actions implemented where applicable;

- 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 4-17 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.

  The rate of protection malfunctions is considered high, which is 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 has embarked on a systematic program to upgrade the protection schemes for the Northern network to computer-based systems, conforming to best industry practice.

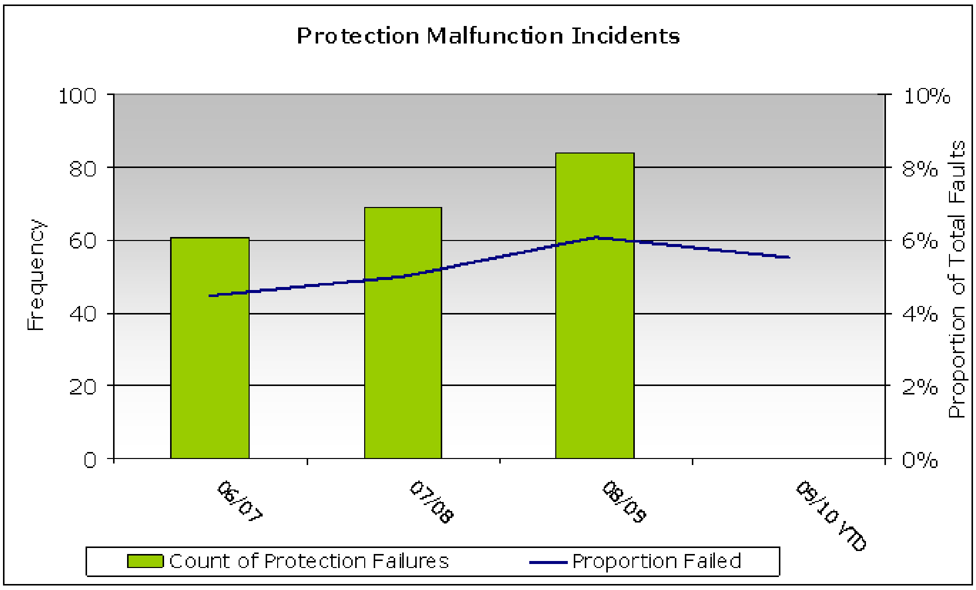


Figure 4-17 : Protection malfunction incidents

- Failure rates by type of equipment are being developed and will be introduced when the TAM project is implemented (refer to Section 7). This will also allow the monitoring and analysis of defect rates; and
- Failures due to unknown causes - 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.

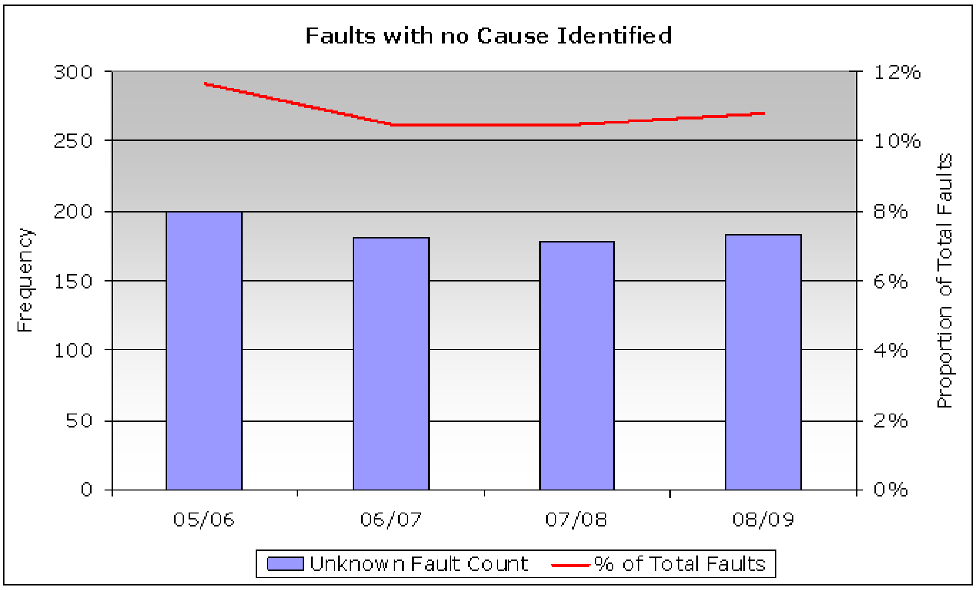


Figure 4-18 : Faults with no cause identified

The frequency and proportion of unknown faults have remained relatively static since reliable records begin in 2005/06 (prior to that date the causes of unknown faults were often guessed). Vector aims to reduce unknown faults to less than 10% of the total fault frequency.

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 7.3.10). This system enables analysis of trends and anomalies in the performance of the network down to the distribution transformer level.

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 beginning of February 2010 To end of February 2010

Region Northern

1 of 2 100% Find | Next Select a format Export

Vector Unplanned Outage Report

From 1/02/2010 To 28/02/2010

Region: Northern

KEY:	Cust Affec	Vector SAIDI	Max Time Off (mins)
	0	0	0
	1-200	0-0.1	0-120
	201-500	0.1-0.2	120-150
	201-1000	0.2-0.5	150-180
	1001+	>0.5	180+

Click on the blue hyperlinks to go into further detail regarding an individual outage.

Event ID	Date	Time	ZBC	System Level	Location	Substation	Main Reason	Sub Reason	Event Cust Affec	Vector SAIDI	Event Max Time Off
197969	28/02/10	20:27	Electrix	Feeder	07MAHO	Coatesville	THIRD PARTY INCIDENT	OTHER	1,598	0.104	37
197965	28/02/10	04:01	Electrix	Feeder	31RANU	Swanson	NO FAULT FOUND	PATROLLED	1,259	0.137	57
197953	25/02/10	13:00	Electrix	Feeder	11LAKE	Hauraki	EQUIPMENT - OH	CROSSARM	223	0.018	42
197951	25/02/10	09:06	Electrix	Zonesub	04BIRKDA		THIRD PARTY INCIDENT	DIG-IN	8,675	0.351	131
197950	24/02/10	23:04	Electrix	Subtrans	(52A) 647		EQUIPMENT - OH	INSULATOR	0	0.000	0
197946	24/02/10	06:26	Electrix	Feeder	38MATA	Warkworth	NO FAULT FOUND	PATROLLED	81	0.011	71
197940	23/02/10	03:05	Electrix	Feeder	09GLED	James Street	ANIMAL	OTHER	119	0.042	187
197939	22/02/10	15:35	Electrix	Feeder	13WAIT	Helensville	EQUIPMENT - OH	OTHER	3	0.001	205
197935	21/02/10	22:15	Electrix	Feeder	30JUNI	Sunset Rd	EQUIPMENT - UG	CABLE	69	0.018	135
197931	20/02/10	13:20	Electrix	Feeder	07SCRE	Coatesville	THIRD PARTY INCIDENT	OVERHEAD CONTACT	708	0.070	116
197929	20/02/10	02:20	Electrix	Feeder	27HUAP	Riverhead	NO FAULT FOUND	PATROLLED	11	0.005	240

Figure 4-19 : Example report from HVEvents showing unplanned events in the Northern region during February 2010

Year 2010 Month March

Day Sunday 7

1 of 1 100% Find | Next Select a format Export

HV Event Report

Events that have on 07 Mar 2010

KEY:	Cust Affec	Vector SAIDI	Max Time Off (mins)	Recent Trend vs SLA
	0	0	0	
	1-200	0-0.1	0-120	OK
	201-500	0.1-0.5	120-150	< SLA
	201-1000	0.5-1	150-180	= SLA
	1001+	>1.0	180+	> SLA

Click on the blue hyperlinks to go into further detail regarding an individual outage.

Unplanned Events

Event ID	Date & Time	Region	System Level	Location	Substation	Main Reason	Sub Reason	Cust Affec	Vector SAIDI	Max Time Off	Faults Last 12mths	FAIFI*
198011	7 Mar 19:30	Northern	Feeder	28AWAR	Sabulite Rd	THIRD PARTY INCIDENT	VEHICLE DAMAGE	324	0.128	208	2	1.2

Planned Events

Event ID	Date & Time	Region	System Level	Location	Substation	Cust Affec	Vector SAIDI	Max Time Off (mins)
198009	7 Mar 08:31	Northern	Feeder	26CENT	Orewa	56	0.005	47
198010	7 Mar 08:04	Auckland	Feeder	HOBS 32	Hobson	2	0.000	21
198008	7 Mar 07:06	Northern	Feeder	37RATA	New Lynn	37	0.006	90

Auto Reclosers Events

Event ID	Date & Time	Region	Location	Substation	Reclose Events last 1mth
198007	7 Mar 00:29	Auckland	OTAR 16	Otara	1

Figure 4-20 : Example of daily fault report from HVEvents reporting system

UNPLANNED HV EVENT DETAILS	
Event ID	198011
Date	07/03/2010 19:30 p.m.
Region	Northern
System Level	Feeder
Substation	Sabulite Rd
Location Code	28AWAR
Location Name	AWAROA RD
Main Reason	THIRD PARTY INCIDENT
Sub Reason	VEHICLE DAMAGE

Operational Details	
ZBC	Electrix
Contractor	Electrix
Operations Engineer	
Field Person	
Comments	Car v pole in Awaroa Rd, Sunnyvale. Emergency shutdown carried out to replace Pole.
Service Request Nr	1-184817033
Defect Number	

Location Details	
Street Address	78 AWAROA ROAD
Suburb	SUNNYVALE
Closest Asset 1	Pole #74496
Closest Asset 2	

Fault Trip Details	
Fault Trips	0
Trip Device	
Device Nr	
Protection Operation	OK
Function	
Protection Comments	
FPI Operation	Not Specified
FPI Comments	

Figure 4-21 : Example of detailed information captured for an individual event in HVEvents

4.2.1.3 Enhancing our Performance for the Future

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
- Targeting major cause contributors to reduce the frequency network 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 defined 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 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 in the year 2000 has been chosen as the base line for reference. The utilisation profiles for the past three years (2006, 2007 and 2008) are plotted. We have 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.

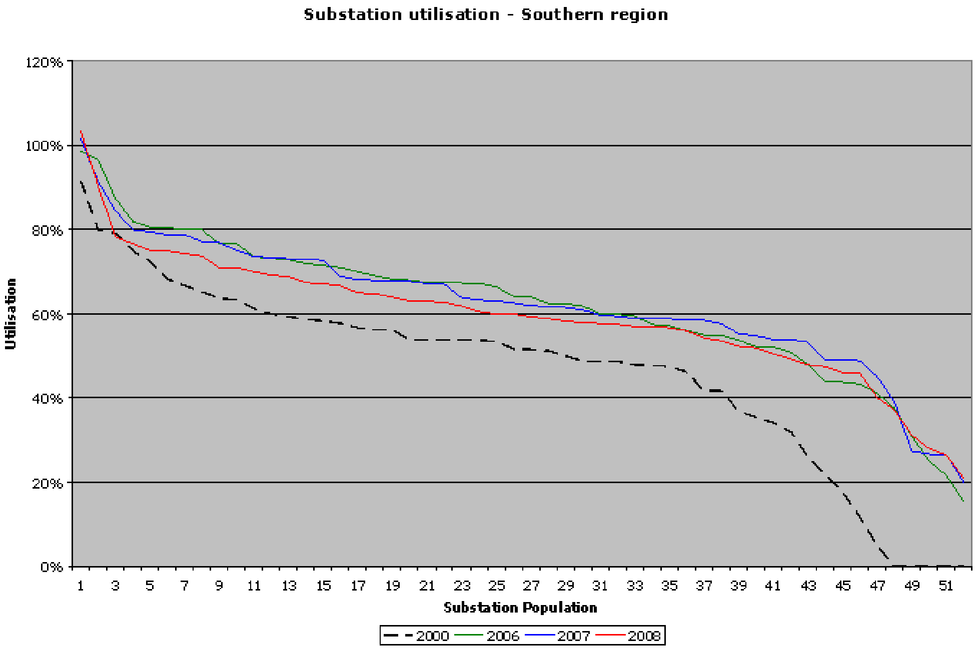


Figure 4-22 : Substation utilisation - Southern region

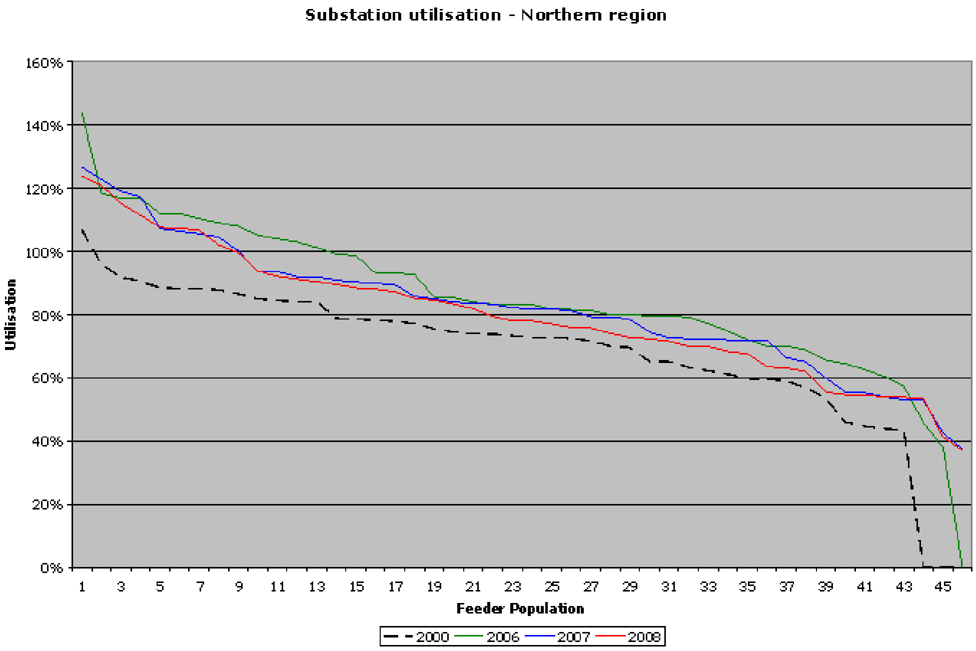


Figure 4-23 : Substation utilisation - Northern region

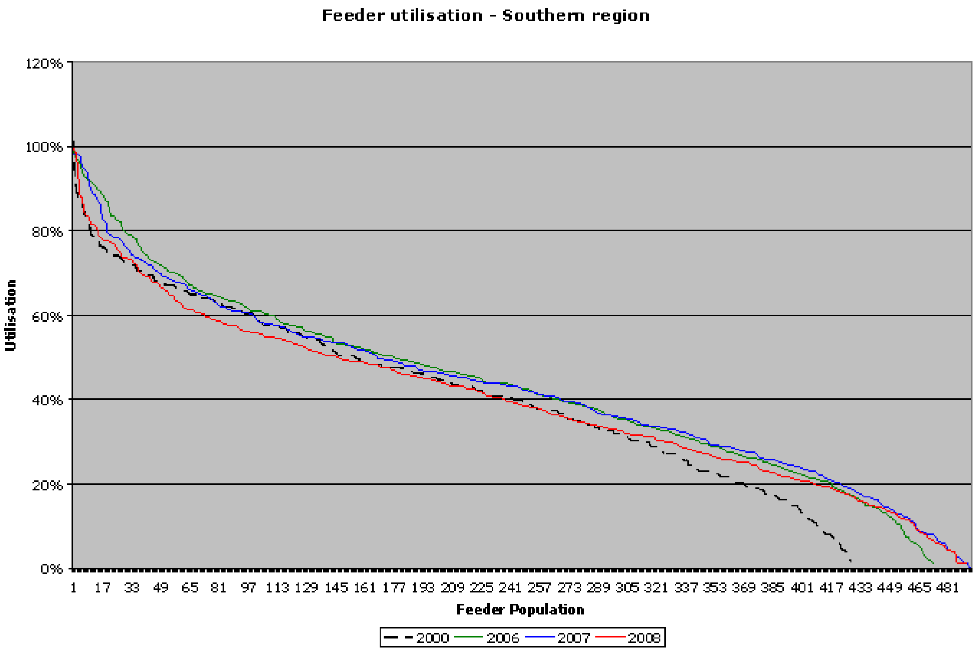


Figure 4-24 : Feeder utilisation - Southern region

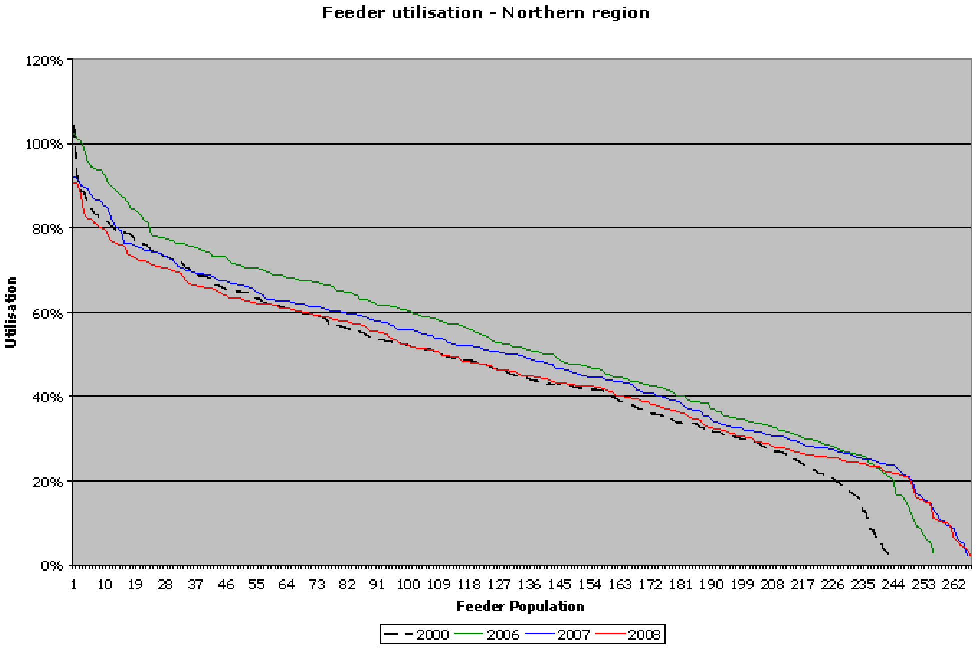


Figure 4-25 : Feeder utilisation - Northern region

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 underutilised or over utilised (at security risk) so that appropriate actions (such as load transfer, demand side management, and network reinforcements) can be taken.

It should be noted that 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 53% on 2000 to 61% in 2008. This represents an eight percentage point increase (or a 15% increase in utilisation over the past eight years). At the top end (high utilisation), the increase is much less significant indicating that off loading of heavily loaded substations is taking place. 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/United Networks merger and the manner in which supply quality and risk was 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 we have 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:

- Residential - ability to supply load 95% of the time following a first fault;
- Commercial/industrial - ability to supply load 98% of the time following a first fault; and
- CBD - N-1 no break; N-2 switched.

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 the following graph, 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.

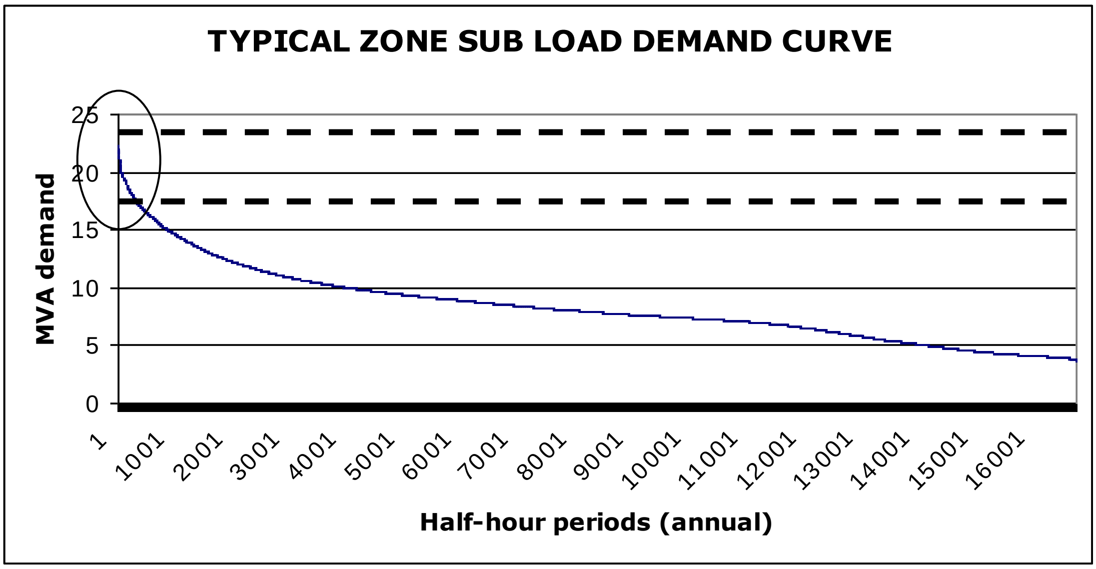


Figure 4-26 : Typical zone sub load demand curve

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 all consumers' normal requirements under normal network conditions. In some cases short-term component overloading is accepted, as shown below.

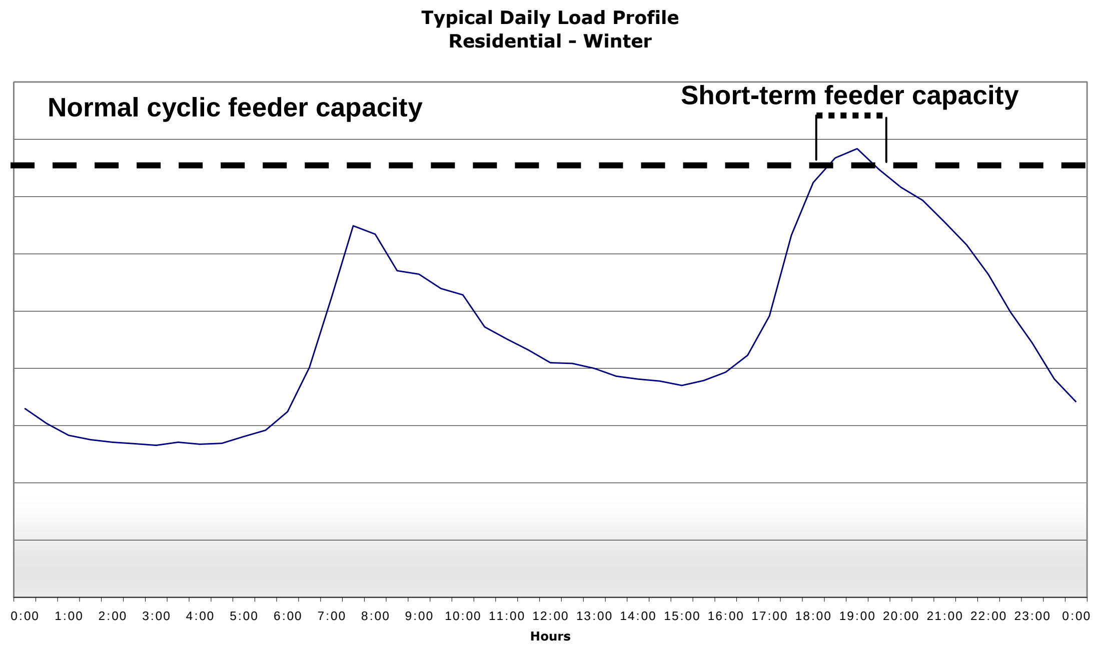


Figure 4-27 : Typical residential (winter) daily load profile

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

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 that 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 that 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 Key Performance Indicators (KPIs), 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, 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 & 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 the table 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 4-4 : 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 fits under 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 & Efficiency

The cost management & 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 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 4-28 below shows the long term trend in lost time injuries at Vector (including FSPs) over the last eight years.

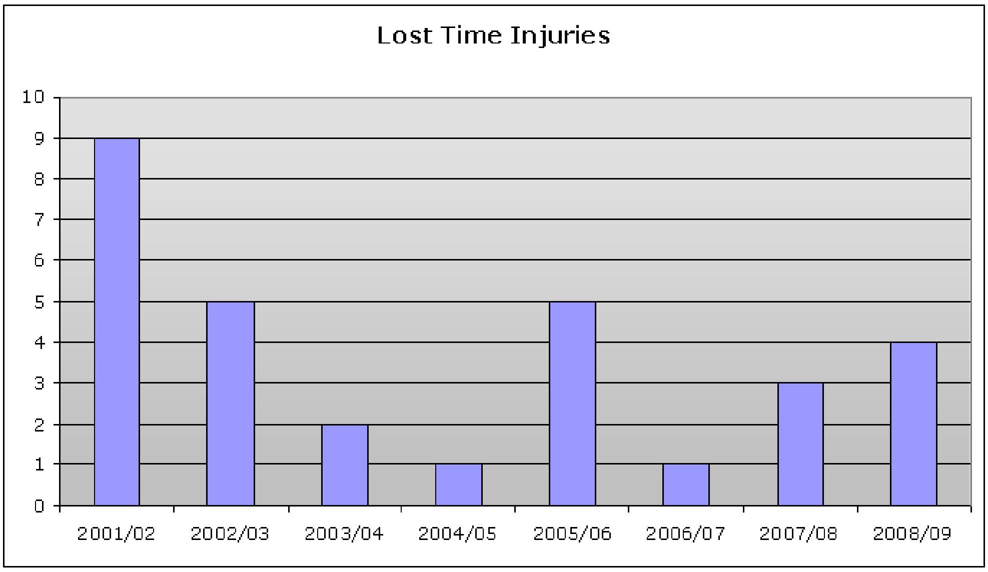


Figure 4-28 : Lost time injuries at Vector (including the gas networks)

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 our vision of zero injuries in the workplace, Vector will place an increased focus on ensuring hazards, where ever possible, are eliminated during the design phase, that our policies and procedures assist our workforce to deliver the right action at the right time, and to focus on personal behaviours to encourage an individual and team safety culture.

5. Network Development Planning

In the context of this Asset Management Plan (AMP), network development refers specifically to growth related projects - those projects which:

- Extend the Vector electricity network to newly developed areas;
- Extend the capacity or supply levels of the existing network to cater for load growth or changing consumer demand;
- Provide new customer connections; or
- Address the relocation of existing services when required as a result of the activities of other utilities or requiring authorities[21].

5.1 Network Development Processes

Vector's network development process involves the planning of the network, budgeting and prioritising the solutions programme; and implementing the planning solutions. It has been reviewed by independent external parties in the past few years with only minor improvements being suggested. These suggestions were incorporated.

5.1.1 Network Planning Process

Vector's primary objectives in network planning are to identify and prevent foreseeable network related security[22], capacity and power quality (PQ) (voltage levels and distortion) problems in a safe, technically efficient and cost effective manner. The planning process involves identifying and resolving:

- Supply quality, security or capacity issues that may prevent Vector from delivering its target service levels;
- Supply to new developments or areas requiring electricity connections; and
- The need to relocate assets, when reasonably required by third parties.

Supply quality problems can be identified from a wide range of sources including PQ measurement and monitoring, power flow and fault level modelling and customer complaint databases.

A good knowledge of asset capacity and capability together with an accurate demand forecast enables an accurate assessment of the network's ability to deliver the required level of security and service. The demand forecast model is a complex programme which processes relevant data including past demand trend, anticipated customer growth, technology trend, demographics, population growth, economic condition, weather pattern, and industry trends.

Solutions addressing network capacity and security constraints may be asset or non-asset based, and the optimal solution may not necessarily result in network augmentation. In evaluating the solution options, the following are considered:

- Review the asset capacity and capability if required using actual site data;
- 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. Compare solutions under similar situations;

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[21] The main requiring authorities are local authorities, ONTRACK and NZTA.
[22] "Security" as used in a planning context means the security of the electricity supply – i.e. the likelihood that supply may be lost.

- Demand side options such as load management or customised pricing to reduce demand on the network;
- Automation to expedite load transfer and restoration times and to increase short term asset capacity;
- Non capacity network solutions such as capacitor banks as possible solutions to low voltage (LV) issues and capacity constraints in low growth areas;
- Upgrade or partial upgrade to 22kV in remote areas supplied by overhead lines as an option to resolve capacity and voltage problems;
- Removing capacity constraints caused by asset components to improve the overall capacity of an asset (for example, upgrade a transformer connection to increase the overall capacity of a substation);
- Taking advantage of the diversity due to different load profiles (residential/industrial/commercial) to reduce overall demand;
- Targeted solutions to satisfy specific requirements of a small group of customers (or individual customers). For example it would be more economic to upgrade the PLC controls or install a UPS in a specialist factory than to implement a general upgrade to the supply quality for the entire district;
- Ensuring that where possible and practical, any solution to a short term issue will meet the long term needs to avoid asset stranding;
- Taking into account how the network will be operated when proposing a network solution;
- Non asset solutions where possible and practical to defer network expenditures. If asset solutions are inevitable, smaller projects are chosen over larger projects to reduce the risk of stranded assets. Early investment is avoided unless there are good reasons to do otherwise (for example, to take advantage of the synergy of implementing in conjunction with projects);
- Aligning the network development programme with other work programmes such as asset replacement to achieve synergy benefits where possible and practical;
- Matching the seasonal network capacities with the respective demand forecast (i.e., summer demand planned based on summer capacities);
- Avoiding reputation damage and consequential financial loss arising from the loss of supply to large groups of customers, or ensuring overloaded assets at risk of premature failure are considered in growth related network augmentation projects; and
- Ensuring recommended solutions are commercially appropriate.

The diagram in Figure 5-1 shows the high level planning and programme implementation processes.

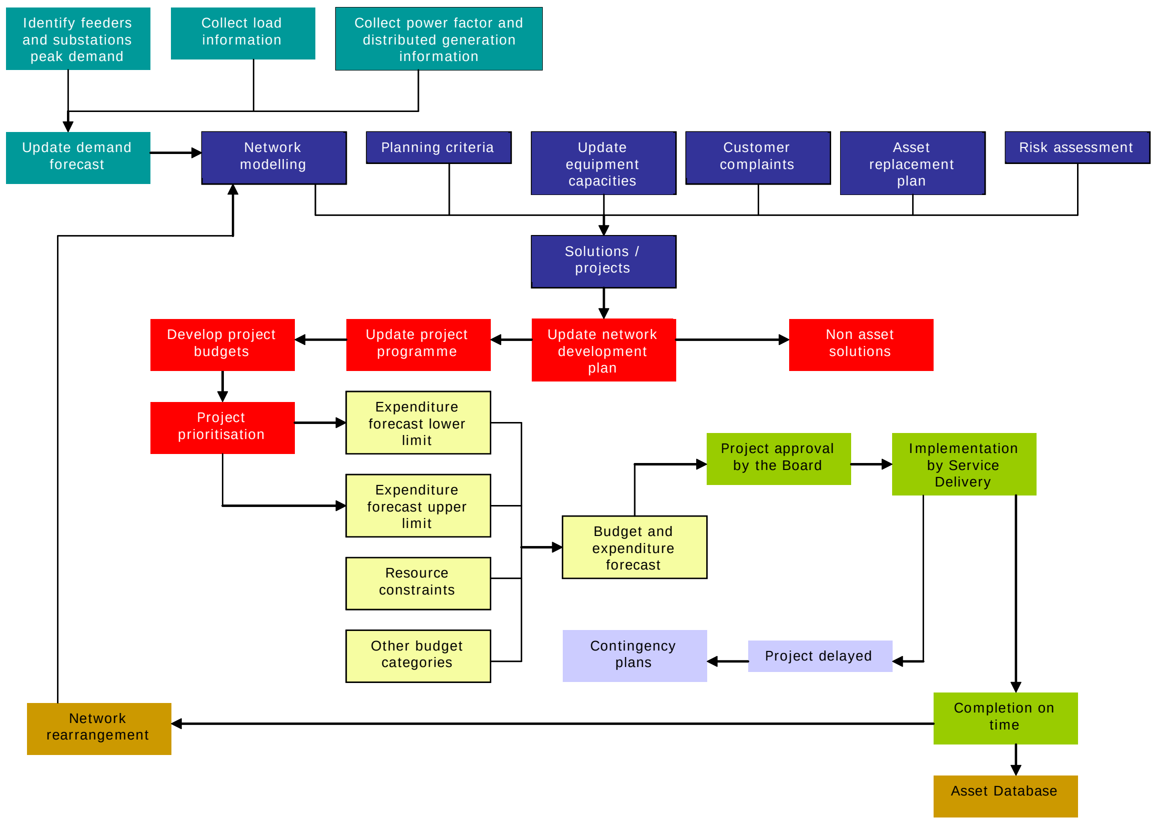


Figure 5-1 : Network development and implementation process

5.1.2 Project Implementation

To enable effective delivery of the capital works programme, an agreed end to end process has been established between Vector's Asset Investment (AI) and Service Delivery (SD) groups. The process tracks each project from conceptual design to project definition through to detailed design and site construction. Once a project is approved, the project is entered into the delivery programme.

5.2 Planning Criteria and Assumptions

Network development planning is concerned with delivering network performance and security at the level of risk acceptable to the Board, or as agreed with customers. The planning principles are encapsulated in a number of standards, with the key document being the security standard. The main planning principles are as follows:

- All network assets will be operated within their design rating to ensure they are not damaged by overloading;
- Network assets will not present a safety risk to staff, contractors or the public;
- The network is designed to meet statutory requirements including acceptable voltage and PQ levels;
- Customers' reasonable electricity capacity requirements will be met[23]. 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;

[23] This includes customers with non standard requirements, where special contractual arrangements apply.

- 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.

Vector has a number of key policies and standards designed underpinning its network planning approach. These policies and standards cover the following areas:

- Network security – Vector's security standard specifies the minimum levels of network capacity necessary (including levels of redundancy) to ensure an appropriate level of supply service;
- Service level - established as part of the Use of Network Agreement with retailers and customers. The service levels reflect expected restoration timeframes and fault frequencies;
- Technical standards - ensure optimum asset life and performance is achieved. They ensure that capital cost, asset ratings, maintenance costs and expected life are optimised to achieve overall lowest cost for Vector. Standardisation also reduces design costs and minimises spare equipment holding costs leading to lower overall project costs; and
- Network parameters – including acceptable fault levels, voltage levels, power factor, etc., providing an appropriate operating framework for the network.

These are explained in the following sections.

5.2.1 Voltage Limits

Sub-transmission voltages are nominally 110kV, 33kV and 22kV in line with the source voltage at the supplying GXP. The voltages used at MV distribution level are nominally 22kV, 11kV and 6.6kV (currently being upgraded to 11kV). The LV distribution network supplies the majority of customers at nominally 230V single phase or 400V three phase. By agreement with the customers, supply can also be connected at 11kV, 22kV or 33kV.

Regulation 53 of the Electricity Regulations 1997 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 fluctuation. Supplies made at other voltages must be kept within +/-5% of the nominal supply voltage except for momentary fluctuation, unless agreed otherwise with 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.

5.2.2 Security Standard

In 1999, the Vector Board approved the Vector security standards, designed to:

- Match the security of supply with customers' requirements and what they are prepared to pay for;
- Optimise capital expenditure (capex) without a significant increase in supply risks; and
- Increase asset utilisation.

These standards accept a small risk that customer supplies may be interrupted when a network fault occurs during peak demand times[24]. The length of time (based on percentage measures) when the sub-transmission network could not meet the N-1 security and the distribution network did not have full backstop was defined with different durations for different categories of customers.

However, even in the event that an interruption should occur, limits are set on the maximum load that would be lost.

Table 5-1 and Table 5-2 summarise the security standard customer service levels used in network planning, for the sub-transmission and for the distribution networks.

Type of Load	Security Standard[25]	Restoration Time Targets[26]
Predominantly residential	N-1 for 95% of time in a year. For the 5% of the time when N-1 security is exceeded.	Southern region: 2.5 hours in urban areas and 3 hours in rural areas Northern region: 3 hours in urban areas and 6 hours in rural areas
Mixed industrial, commercial and residential.	N-1 for 98% of time in a year. For the 2% of the time when N-1 security is exceeded.	Southern region: 2.5 hours in urban areas and 3 hours in rural areas Northern region: 3 hours in urban areas and 6 hours in rural areas
Predominately industrial	N-1 no break for 98% of time in a year.	Southern region: 2 hours
Auckland CBD	N-1 no break and N-2 switched.	2 hours

Table 5-1 : Sub-transmission security standard customer service levels

Type of Load	Security Standard	Restoration Time Targets
Predominantly residential	Full backstop for 95% of time in a year	Southern region: 2.5 hours in urban areas and 3 hours in rural areas Northern region: 3 hours in urban areas and 6 hours in rural areas
Mixed industrial, commercial and Residential.	Full backstop for 98% of time in a year	Southern region: 2.5 hours in urban areas and 3 hours in rural areas Northern region: 3 hours in urban areas and 6 hours in rural areas
Predominately industrial	Full backstop for 98% of time in a year	Southern region: 2 hours

[24] A true deterministic standard, such as N-1, implies that supply will not be lost after a single fault at any time. The Vector standard accepts that for a small percentage of time, a single fault may lead to outages. By somewhat relaxing the deterministic standard, significant reductions in the required asset capacity and redundancy levels become possible.

[25] Except for the "N-1 no break" within the CBD all contingent events are assumed to be "switched" (i.e. not "no-break")

[26] http://www.vectorelectricity.co.nz/residential/service-standards, http://www.vectorelectricity.co.nz/business/service-standards,

Type of Load	Security Standard	Restoration Time Targets
Auckland CBD	Full backstop for 99.5% of time in a year	2 hours
Overhead spurs*	No backstop	Repair time of faulty equipment
Underground spurs*	No backstop	Repair time of faulty equipment

*For overhead spur feeders with loads of less than 1MVA urban and 2.5MVA rural, "N" security is offered. Similarly for underground spur feeders with loads less than 400kVA, "N" security is offered.

Table 5-2 : Distribution security standard customer service levels

5.2.2.1 Impact of Network Configuration

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.

5.2.3 Fault Level

The effects of a fault current on a network component include:

- Heating effect - in proportion to the duration of the fault, resistance of the network component and the square of the fault current passing through the network component (I^2rt);
- Magnetic force – in proportion to the fault current according to the right hand rule; and
- Arc breaking – the ability to break the fault at current zero.

While heating and magnetic effects have an impact on all network components, arc breaking capability applies only to circuit breakers (CBs). The network is designed to meet the fault levels[27] as shown in the following table.

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 5-3 : Fault levels

Equipment must be designed and operated to within the maximum prospective fault current of the network at all times.

[27] Refer to ENS-ND05

5.2.4 Equipment Capacity

All equipment (transformers, cables, switchgear, etc.) has a finite load carrying capacity depending on the demand characteristics (flat, fluctuating, or cyclic) and the environment in which the equipment operates (ambient temperature, proximity with other equipment, ability for heat dissipation, etc.). Vector has a team of specialists that advise on how network components can be rated. The planners then assess the overall capacity of the circuit based on the capacities of the individual components. Where load patterns allow, this takes into account cyclical or short-term capacity ratings.

5.2.5 Power Factor

The Connection Code promulgated by the Electricity Commission as Part F of the Electricity Governance Rules (EGR) 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.

Vector and lines companies more generally consider the ruling on unity power factor as unachievable in practice, and not economically efficient when compared with the small benefit it brings[28]. Vector has therefore advised the System Operator that it is non-compliant on this requirement. The issue is being further pursued through various channels.

5.2.6 GXP Standard

Vector takes supply from the transmission grid at GXPs owned by Transpower. For these, Vector provides input into the functional requirements while Transpower is responsible for specifying the technical requirements.

Vector's general requirements at GXPs can be categorised by voltage, voltage limits, security, capacity and fault level. In general, Vector takes supply at 110kV and 33kV. 22kV is supplied at Penrose, Roskill and Otahuhu but will not be expanded into other new GXPs. There is a plan to phase out the 22kV supply at Penrose. The long term intention is to phase out the 22kV sub-transmission network when the assets reach the end of their economic lives.

The Connection Code specifies prospective fault levels at Transpower's GXPs as follows:

Supply Voltage	Prospective Fault Current
110kV	31.5kA
33kV	25.0kA
22kV	25.0kA

Table 5-4 : Prospective fault level at Transpower's GXPs

[28] 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.

5.3 Planning Methodology

As noted before, the network planning process involves identifying and resolving:

- Upcoming supply quality, security or capacity issues that may prevent Vector from delivering its target service levels;
- Supply to new developments or areas requiring electricity connections; and
- The need to relocate assets, when reasonably required by third parties.

In all cases, effective design requires consideration of the forecast demand, the capacity of equipment and the impact of the environment in which the equipment will operate.

The demand forecast model is aimed at providing an accurate picture of future demand growth (or decline) so that investment decisions can be made with confidence. When used in conjunction with equipment ratings (influenced by operating conditions), it is possible to plan for the required capacity and security margins within the network. The security standards are defined to reflect the levels of acceptable supply risk to Vector, irrespective of how the demand growth or equipment rating is assessed. This ensures that network investments are made on a consistent basis.

In order to avoid predetermined outcomes, it is important that each of these three components, viz., demand forecasting, equipment rating assessment and security standard definition, are developed independently.

The methodology used to assess equipment rating reflects the true capacity of the equipment under field conditions, independently of the manner in which demand forecasts and security standards are developed.

5.3.1 Demand Forecasting Assumptions

The following is a summary of the assumptions made in preparing the demand projection used in the AMP:

- "Normal" years, without extreme winter or summer weather conditions;
- A linear relationship exists between employment growth, and industrial and commercial demand;
- Residential demand is related to customer connections and hence the number of households. While individual customer demand varies, an average customer demand can be derived at a distribution feeder level;
- Both summer and winter demand forecasts are prepared. The summer demand forecast has been introduced to monitor changing summer consumption pattern (e.g. arising from increased use of heat pumps) and reduced equipment ratings;
- Connected embedded generators are assumed to maintain current operating patterns. New embedded generators will be reflected as information becomes available. Generation at landfill sites will be monitored and decommission plans reflected in the demand forecast;
- Vector's load management strategy is to maximise use of the existing load control assets until a replacement technology is available – load control is used to reduce maximum demand at zone substations; and
- The impact of emerging technologies on the network has been accounted for in the demand forecast, based on our present knowledge and foresight. Emerging technologies (see Section 3) includes heat pumps, electric vehicles (EVs), photovoltaic (PV) generation and smart home technologies.

5.3.2 Network and Asset Capacity

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. Major components include:

- Cables;
- Over head lines;
- Transformers; and
- Switchboards.

Determining the capacities of these network components require a detailed assessment of each sub-component within the 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.

5.3.2.1 Cables

The analysis of MV cable rating is complex due to the various cable types, installation practices, surrounding soil makeup and moisture content, solar gain and preloading conditions. To help in determining the rating of a cable, Vector uses the cable rating modelling tool "CYMCAP", a product of CYME Corp of Canada. CYMCAP is designed 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 deterioration of their electrical properties.

5.3.2.2 Overhead Lines

In general overhead lines may be considered as air insulated cables supported by insulating structures (poles, cross arms, insulators). The environmental/operating conditions play a big 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 IEEE Standard 738:1993 method for calculating conductor ratings. A computer package called "CONAMP" is used to determine the maximum rating of OH conductors.

5.3.2.3 Transformers

Technical specifications for the purchase of power transformers reflects Vector's network planning standards and network operating practices. These have changed significantly over time due to changes in network configuration, equipment standards and planning criteria. The present Vector network is made up of the previous AEPB (Auckland Electric Power Board) and the WEPB (Waitemata Electric Power Board) networks. These two organisations had very different planning and operating philosophies, which is reflected in the assets.

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.

In the Southern region power transformers have been designed around a base rating (usually ONAN) with a two hour extended operating (emergency) rating. This extended operating rating has no calculated loss of life of the unit. The intent of the extended operating range is to allow spare capacity for a limited time in case of the failure of another transformer, or during over-load conditions. This allows time for network switching in order to offload a station to mitigate the conditions.[29]

In the Northern region however, power transformer were specified differently - following a British standard. This standard used a 12/24 hour rating scheme. Vector interprets this as a maximum operating rating and that these units do not have a practically useable 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, with a 120% of ONAN for normal cyclic loading.

Regardless of the transformer specification, Vector has established three operating temperatures that should never be exceeded, these are:

- Top oil temperature - 105ºC;
- Conductor hot-spot temperature - 125ºC; and
- Metallic part temperature - 135ºC.

Taking into account the different designs of the power transformers, oil and winding temperature trips are assigned independently depending on year of manufacture, knowledge of the cooling system, review of type test certificate information, construction standard and the ratings of associated components such as tap changers, bushings, connection cables and the like.

In general, due to the nature of the bulk modulus, power transformers have the potential to operate beyond the nameplate rating provided the unit can be kept cool and the temperature hot spot isn't exceeded to the extent that the insulating materials around the winding are burnt or made too brittle, which could cause failure. In practice the operation of power transformers is guided by the oil and winding temperature readings. Oil temperature measurements and winding temperature simulation collected from the site are sent to the control room via the SCADA network and compared against the preset threshold, initiating an alarm to alert the control operator or a trip signal to prevent excessive damage of the transformer.

5.3.2.4 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 where as switchgear (primarily outdoor apparatus) takes into consideration a much more 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 was produced.

[29] It should be noted that the two hour emergency rating is not the same on all power transformer on the network. The OEM type test certificates and design specification need to be referred to determine the two hour emergency rating.

5.3.3 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 risk matrix to obtain a peer-wise comparison. The risk matrix looks at the consequences of not undertaking the project, by considering wider company factors such as operational, health and safety, environmental, legal, financial, reputational, and regulatory risk to develop a "project necessity" rating or priority rating 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.

5.4 Demand Forecasting

5.4.1 Demand Forecasting Methodology

A spreadsheet based model has been developed for electricity demand forecasting. The model covers the winter and summer forecasts for the next ten years. Input data used to derive the demand forecast is based on:

- Historical demand records (summer and winter) of feeders, zone substations and GXPs;
- Statistics New Zealand employment and household projections;
- Employment projections from expert surveys and investigations;
- Known future developments in the business and residential sectors;
- Known future embedded generation;
- Planned capacitor installations;
- Planned load transfers within the network;
- Anticipated embedded generation including PV generation;
- Anticipated demand growth due to emerging technologies:
    - New technology (electric vehicles, PV panels, etc);
    - Changing customer behaviour (usage of heat pumps); and
    - Regulatory influences (energy efficiency, emission reduction).
- Relative contribution to the demand on feeders and zone substations by sector (residential versus business).

The model contains a list of all 11kV feeders and their historical winter and summer peak demands. Trending the previous five years' historical peak demand records provides a "starting" demand to derive a linear regression based forecast.

This approach removes any short term demand variability due to factors such as weather, etc. Adjustments are made for known network demand distortions such as brief high load due to load transfers, large load increases/decreases, installation of capacitor banks or embedded generation. An identical process is followed for the summer demand forecast.

Capacitor and embedded generation capacities are deducted from the "starting" demand to avoid underestimating demand when calculating the forecast. The forecast is calculated, as described below, and the capacitor and generation capacities are added back into the forecast.

Vector's distribution area is divided into small pockets of land aligning with Census Area Units (CAUs) as used by Statistics New Zealand. Data on population and employment forecasts is obtained from Statistics New Zealand and local authorities based on these CAUs. Population and employment growth trends are used as a proxy for forecast residential and business growth rates respectively. These are calculated at a CAU level to ensure adequate granularity in the demand forecast.

This is translated into demand at a distribution feeder level by weighting the residential/business contribution to the demand and the population/employment growth in the CAU areas through which the feeder passes. Residential and business energy records are used as a proxy for the associated 11kV feeder demand contribution by the two customer segments (i.e. residential and commercial/industrial).

Where multiple feeders are allocated to the same CAU, load is allocated on the basis of the relative feeder length within the CAU. Known developments (commercial, subdivisions) are separately included in the demand forecast. Estimates for the impact of emerging technologies (especially heat pumps) are included in the forecast as a net percentage load increase.

The growth rates for each feeder are applied to the "starting" demand to obtain a ten year linear regression demand projection for the feeder. The forecast demand is compared to the feeder (or sub-transmission) rating to identify network security margins. Where the forecast demand exceeds the circuit rating, a constraint is identified. These feeders are further reviewed to confirm whether they breach the 99.5%, 95% or 98% "N-1" availability as part of the security standards. This involves totalling the number of half hours in excess of the summer and winter equipment rating based on the pro-rated summer and winter load profiles. If these thresholds are exceeded options are considered for addressing the breach.

The feeder "starting" demands are aggregated and compared with the actual historical zone substation "starting" demand to calculate a diversity factor. Totalling feeder forecast demands and applying the diversity factor allows the zone substation demand forecast to be developed. The exercise is repeated for the summer zone substation demand forecast.

In the same manner, zone substation projections are aggregated to provide GXP demand projections.

5.4.2 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 are to:

- Act 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, 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 (e.g. PV panels, electric vehicles (EVs), etc) or global trends (e.g. 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;
- Continuous review of network performance to identify and apply remedial action to poor performing areas; and
- Use of non network solutions where possible, to improve network utilisation and capital efficiency. Load control is a good example – moving demand from one time segment to another without adversely affecting the customer, while deferring the need for new network investment.

5.4.2.1 Large development projects

Vector, as a requiring authority, receives early notification of resource consent applications. This allows us to keep abreast of imminent projects and commence early discussions with developers and consultants about proposed electricity supply needs. For the larger projects in particular, the earlier that planning commences the more ability Vector has to optimise designs, obtain best procurement rates and maximise potential spin-off or synergy benefits from developments.

The additional loads expected from development projects are captured in the demand forecast as a best estimate of when this will be experienced, and hence when network augmentation will be required. Regular forecasting (summer and winter) allows the timing of the individual projects to be re-evaluated and the forecasts adjusted accordingly. In high growth areas, a larger capacity buffer may be maintained to allow for unexpected load increases or unexpected delays in the delivery of solutions.

5.4.3 Impact of Embedded Generation

Apart from the large embedded (landfill gas) generation sites at Redvale, Rosedale, Greenmount and Whitford and the CHP generation at Auckland Hospital, other currently embedded generation is either relatively small and does not have a noticeable impact on the network, or is designed to operate as an isolated power supply not coupled to the network. Where it does impact on the network, the generation is included in the load forecast model as described in Section 5.4.

Table 5-5 summarises the generation applications processed in the 12 months to the end of 2008. While the figures for 2009 have yet to be finalised indications are that they will be similar to 2008.

Generation Size Range	Total "Application" Capacity	Total "Approved" Capacity	Number of Applicants
10kW or less	9.32kW	9.32kW	6
Greater than 10kW	4,630kW	1,650kW[30]	6

Table 5-5 : Generation connection applications for 2008

5.4.4 Demand Management

Vector's load control strategy aims to offer:

- Network performance improvements by shedding domestic water heater load in the event of faults. Load control 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.

Load control is also used to provide shedding capacity under emergency conditions (as administered by the System Operator under its automatic under-frequency load shedding scheme (AUFLS). On top of this Vector uses some of the load shedding capacity to bid on the demand side market.

The existing load management assets have been in service since the early 1970's. Changes to the transmission and retail pricing methodology mean that load control to contain GXP demands is no longer the key driver, nor the revenue earner it use to be to support the load control system.

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 grids expected to emerge over the medium term, further investment in conventional load control plants needs to be carefully considered.

[30] The process involves a two part application. The initial application tests the feasibility of connecting generation with the utility to identify any technical issues while the final application is a "request to connect". The difference in this case is because the final application (or "request to connect") has not been submitted by the applicant.

The impact of these evolving technologies is unlikely to impact demand significantly until the latter part of the (ten year) planning period. Until new technology offers practical and feasible alternatives, the existing load management systems will be retained. Development of new demand management technologies will be closely monitored.

5.4.5 Load Forecasts

Based on the available information and using the methodology described earlier, the projected demand at each of Vector's existing zone substations and bulk infeed substations over the planning period is given in the following tables. The table below shows the winter peak demand projection for the bulk supply substations and zone substations for the Northern and Southern regions.

Lichfield substation is also included in the projection. Table 5-7 shows the corresponding peak demand projection for summer.

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Atkinson Road	24.0	18.9	21.0	21.3	21.6	21.9	22.1	22.4	22.7	23.0	23.3	23.6	23.9	N	Y		Project underway to reinforce substation
Auckland Airport	58.6	18.3	20.3	26.1	32.1	34.3	36.5	38.8	41.0	44.1	47.2	49.1	51.0	N-1	Y	2011	Customer substation, managed by customer
Auckland Hospital	10.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	N	Y		Sufficient 11kV backstop capacity
Avondale	48.0	28.2	29.1	29.4	29.8	30.2	30.5	30.9	31.3	31.7	32.0	32.4	32.8	N-1	Y		
Bairds	48.0	23.5	23.2	23.7	24.1	24.6	25.1	25.5	26.0	26.4	26.9	27.4	27.8	N-1	Y		
Balmain	12.0	8.6	9.6	9.7	9.9	10.0	10.1	10.2	10.4	10.5	10.6	10.8	10.9	N	Y		
Balmoral	24.7	15.1	15.1	15.2	15.3	15.4	15.5	15.6	15.7	15.8	15.9	16.0	15.1	N-1	Y		
Belmont	28.0	14.3	14.7	14.5	14.6	14.7	14.8	14.9	15.0	15.0	15.1	15.2	15.3	N	Y		
Birkdale	30.0	23.9	24.1	24.3	24.5	24.6	24.8	25.0	25.2	25.4	25.5	25.7	25.9	N	Y		
Brickworks	13.0	9.8	9.8	10.2	10.4	10.5	10.7	10.9	11.1	11.3	11.4	11.6	11.8	N	Y		
Browns Bay	28.0	15.9	17.2	17.6	18.1	18.5	19.0	19.5	20.1	20.6	21.1	21.7	22.3	N	Y		
Bush Road	42.0	28.2	30.1	31.0	31.9	32.9	33.9	35.0	36.0	37.1	38.3	39.4	40.6	N	Y		
Carbine	40.8	24.2	19.4	19.7	20.0	20.3	20.6	20.9	21.2	21.5	21.7	22.0	22.3	N-1	Y		
Chevalier	20.4	18.9	18.6	18.8	19.0	19.3	19.5	19.7	19.9	20.2	20.4	20.6	20.8	N-1	Y		Sufficient 11kV backstop capacity
Clevedon	5.5	3.2	4.2	4.3	4.4	4.6	4.7	4.8	5.0	5.1	5.2	5.3	5.5	N	Y	2017	Sufficient 11kV backstop capacity
Coatesville	12.0	9.3	9.7	9.8	10.0	10.2	10.3	10.5	10.7	10.9	11.1	11.3	11.5	N	Y		
Drive	48.0	32.2	27.7	27.9	28.1	28.3	28.8	29.3	29.8	30.3	30.8	31.0	31.3	N	Y		Hillsborough substation
East Coast Road	24.0	16.0	18.8	19.1	19.6	20.1	20.6	21.4	22.2	23.0	23.8	24.6	25.4	N	Y	2013	Rosedale substation
East Tamaki	48.0	16.4	17.1	17.3	17.5	17.7	18.0	18.2	18.4	18.6	18.9	19.1	19.3	N-1	Y		
Forrest Hill	38.0	17.6	17.9	18.0	18.1	18.2	18.3	18.4	18.6	18.7	18.8	18.9	19.1	N-1	Y		
Freemans Bay	45.6	19.2	21.0	21.3	21.7	22.5	23.8	24.6	25.0	25.4	25.7	26.1	26.5	N-1	Y		
Glen Innes	17.9	15.6	11.1	11.2	11.5	12.1	12.3	12.5	12.7	13.0	13.2	13.4	13.6	N	Y		St Johns substation underway

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Greenmount	70.4	39.7	42.2	43.3	44.4	45.5	46.7	47.9	49.1	50.4	51.7	53.0	54.3	N-1	Y		
Gulf Harbour	24.0	7.4	7.5	7.6	7.7	7.8	7.9	8.0	8.1	8.2	8.3	8.4	8.5	N	Y		
Hans	33.6	23.5	23.4	23.8	24.3	24.7	25.2	25.7	26.1	26.6	27.0	27.5	27.9	N-1	Y		
Hauraki	13.0	9.0	9.1	9.3	9.5	9.7	9.9	10.1	10.3	10.5	10.8	11.0	11.2	N	Y		
Helensville	18.0	13.0	13.8	14.1	14.4	14.7	15.0	15.3	15.7	16.0	16.3	16.7	17.1	N	Y	2013	Second transformer at Waimauku
Henderson Valley	28.0	21.2	22.4	22.8	23.2	23.6	24.0	24.5	24.9	25.4	25.8	26.3	26.7	N	Y		
Highbury	15.0	11.4	11.6	11.8	12.0	12.1	12.3	12.5	12.7	12.9	13.0	13.2	13.4	N	Y	2013	Second transformer
Hillcrest	48.0	23.6	26.7	27.0	27.3	27.7	28.0	28.4	28.7	29.1	29.5	29.8	30.2	N	Y		
Hobson 110/11kV	50.0	25.2	25.7	26.4	27.7	28.4	29.2	29.9	30.6	31.3	32.0	32.7	33.4	N	Y		11kV to 22kV conversion
Hobson 22/11kV	30.0	15.6	16.5	16.9	17.4	17.9	18.3	18.8	19.3	19.7	20.2	20.6	21.1	N	Y		11kV to 22kV conversion
Hobsonville	32.0	21.6	21.9	22.3	22.6	23.0	23.4	23.8	24.1	24.5	24.9	25.3	25.8	N	Y		
Howick	61.6	39.8	40.3	40.5	40.7	40.9	41.1	41.3	41.5	41.7	41.9	42.1	42.3	N-1	Y		
James Street	32.0	24.1	24.0	24.3	24.5	24.8	25.1	25.3	25.6	25.9	26.2	26.5	26.7	N	Y		
Keeling Road	24.0	10.6	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.7	11.9	12.1	12.3	N	Y		
Kingsland	48.0	23.7	23.5	23.8	24.1	24.4	25.1	25.4	25.7	26.0	26.3	26.5	26.8	N-1	Y		
Laingholm	17.0	9.1	8.0	8.1	8.3	8.5	8.6	8.8	9.0	9.1	9.3	9.5	9.7	N	Y		
Lichfield	24.0	6.9	6.9	6.9	7.2	7.6	8.0	8.3	8.7	9.0	9.4	9.8	10.0	N-1	Y		
Liverpool	60.0	44.9	49.9	51.1	47.7	48.8	50.0	51.1	52.2	53.3	54.4	55.5	56.0	N-1	Y		
Mangere Central	56.0	27.9	32.8	33.5	34.2	35.0	35.8	36.6	37.3	38.0	38.8	39.6	40.4	N-1	Y	2010	Transfer load to Mangere West substation
Mangere East	46.0	26.8	27.4	27.9	28.5	29.1	29.7	30.3	30.9	31.6	32.2	32.9	33.6	N-1	Y	2015	Transfer load to Mangere West substation
Mangere West	70.7	13.4	16.0	17.2	17.6	18.1	18.6	19.1	19.5	19.9	20.4	20.8	21.2	N-1	Y		
Manly	30.0	15.6	16.5	17.3	17.7	18.1	18.5	18.9	19.3	19.7	20.2	20.6	21.1	N-1	Y		
Manukau	56.0	30.1	30.8	31.6	32.3	33.1	34.0	34.8	35.6	36.4	37.2	38.0	38.9	N-1	Y		

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Manurewa	70.4	54.3	53.4	54.2	55.0	55.8	56.6	57.5	58.3	59.1	59.9	60.7	61.5	N-1	Y	2019	Transfer load to Clendon substation
Maraetai	24.0	6.8	5.7	5.9	6.2	6.4	6.7	7.0	7.2	7.4	7.6	7.8	8.0	N-1	Y		
McKinnon	48.0	17.8	18.5	19.3	20.2	21.1	22.1	23.1	24.1	25.2	26.4	27.6	28.9	N-1	Y		
Mcleod Road	16.0	12.7	12.9	13.0	13.2	13.3	13.5	13.7	13.8	14.0	14.1	14.3	14.5	N	Y		
McNab	72.0	43.4	45.7	46.2	47.6	48.2	48.7	50.1	51.6	52.1	52.7	53.2	53.8	N-1	Y		
Milford	14.0	9.4	8.8	8.9	9.1	9.2	9.3	9.4	9.6	9.7	9.8	9.9	10.1	N	Y		
Mt Albert	13.7	9.9	9.7	9.8	9.9	10.0	10.2	10.3	10.4	10.5	10.7	10.8	10.9	N	Y	2015	Offload Mt Albert in 2015
Mt Wellington	48.0	24.2	22.4	22.8	24.0	24.9	25.3	25.7	26.2	26.6	27.0	27.5	27.9	N-1	Y		
New Lynn	30.0	15.4	14.5	14.8	15.0	15.3	15.5	15.8	16.0	16.3	16.6	16.8	17.1	N	Y		
Newmarket	72.0	38.6	37.8	38.3	40.8	44.7	47.0	50.1	52.5	54.8	57.2	59.7	61.3	N-1	Y		
Newton	35.7	19.8	20.3	20.6	21.0	21.4	21.8	22.2	22.5	22.9	23.2	23.6	24.0	N-1	Y		
Ngataringa Bay	14.0	8.2	8.5	8.5	8.5	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	N	Y		
Northcote	15.0	9.4	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.5	9.6	9.7	9.8	N	Y		
Onehunga	19.3	21.7	13.8	13.9	14.1	14.3	14.4	14.6	14.8	15.0	15.2	15.4	15.6	N	Y		Hillsborough substation
Orakei	40.6	26.2	20.5	20.7	21.4	22.7	23.5	23.8	24.0	24.3	24.6	24.9	25.2	N	Y		St Johns substation
Oratia	15.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	N	Y		
Orewa	30.0	13.8	13.7	14.5	15.4	16.4	17.4	18.6	19.8	21.2	22.7	24.3	26.1	N-1	Y		
Otara	34.8	29.1	28.6	30.3	32.1	34.0	36.1	38.4	40.5	42.7	45.1	47.7	50.3	N-1	Y	2018	Flatbush substation
Pacific Steel	80.0	64.8	71.6	71.6	71.6	71.6	71.6	71.6	71.6	71.6	71.6	71.6	71.6				Customer substation, managed by customer
Pakuranga	47.8	23.1	24.7	24.9	25.0	25.1	25.3	25.4	25.6	25.7	25.8	26.0	26.1	N-1	Y		
Papakura	44.0	24.1	25.8	26.4	26.5	26.7	26.8	27.0	27.1	27.2	27.3	27.5	27.6	N-1	Y		
Parnell	23.9	10.8	11.6	11.8	11.9	12.1	13.2	14.3	14.5	14.7	14.9	15.1	15.3	N-1	Y		
Ponsonby	28.8	17.0	18.1	18.2	18.3	18.4	18.5	18.6	18.7	18.8	18.8	18.9	19.0	N	Y		Upgrade project underway
Quay	48.0	21.7	22.5	23.2	23.9	25.0	26.5	28.1	28.8	29.5	30.3	31.1	31.9	N-1	Y		Sufficient 11kV backstop capacity

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Red Beach	24.0	12.7	12.9	13.2	13.5	13.8	14.2	14.5	14.9	15.2	15.6	16.0	16.4	N	Y		
Remuera	48.0	32.9	24.4	24.6	25.3	26.0	29.1	31.3	32.6	33.8	34.1	34.5	34.8	N	Y		St Johns substation
Riverhead	18.0	12.5	13.7	14.0	14.3	14.7	15.0	15.4	15.7	16.1	16.4	16.8	17.2	N	Y		
Rockfield	43.6	19.1	21.7	22.0	24.5	27.3	27.7	28.0	28.3	28.6	28.9	29.3	29.6	N-1	Y		
Rosebank	48.0	24.6	23.2	23.4	23.7	23.9	24.1	24.4	24.6	24.8	25.0	25.2	25.5	N-1	Y		
Sabulite Road	26.0	18.8	19.7	20.0	20.3	20.6	20.8	21.1	21.4	21.8	22.1	22.4	22.7	N	Y		
Sandringham	48.0	21.6	21.8	25.9	26.1	26.3	26.5	26.7	26.9	27.1	27.3	27.6	27.8	N-1	Y		
Simpson Road	9.0	7.4	7.9	8.0	8.2	8.3	8.5	8.7	8.8	9.0	9.2	9.4	9.5	N	Y		
Snells Beach	9.0	5.9	6.0	6.1	6.1	6.2	6.3	6.4	6.5	6.6	6.7	6.8	6.8	N	Y	2019	Sandspit substation
South Howick	47.1	30.5	31.4	31.6	31.9	32.2	32.5	32.7	33.0	33.2	33.5	33.7	34.0	N-1	N	2009	Transfer load to Howick Substation
Spur Road	14.0	10.6	10.9	11.4	11.9	12.4	13.0	13.5	14.1	14.8	15.4	16.1	16.8	N	Y		
St Heliers	34.9	24.1	23.3	23.5	23.6	23.8	24.0	24.2	24.4	24.5	24.7	24.9	25.1	N	Y		Sufficient 11kV backstop capacity
Sunset Road	30.0	18.0	20.3	20.5	20.7	20.9	21.1	21.3	21.5	21.7	21.8	22.0	22.2	N	Y		
Swanson	15.0	14.0	13.9	14.2	14.5	14.8	15.1	15.5	15.8	16.1	16.5	16.9	17.2	N	Y	2013	Ranui and Waitakere substations
Sylvia Park	48.0	11.1	18.9	19.1	21.1	23.1	24.2	24.4	24.6	24.8	25.0	25.1	25.3	N-1	Y		
Takanini	36.0	19.6	18.8	19.6	20.0	20.4	20.9	21.3	21.7	22.1	22.6	23.0	23.5	N-1	Y	2018	Takanini South substation
Takapuna	24.0	9.3	9.0	9.2	9.3	9.5	9.6	9.8	10.0	10.2	10.3	10.5	10.7	N	Y		
Te Atatu	28.0	20.2	20.5	20.8	21.0	21.3	21.5	21.8	22.0	22.3	22.5	22.8	23.1	N	Y		
Te Papapa	43.7	23.5	18.4	18.6	19.3	19.9	20.2	20.5	20.7	21.0	21.2	21.4	21.7	N-1	Y		
Torbay	13.0	10.4	10.5	10.7	10.8	11.0	11.2	11.4	11.6	11.8	12.0	12.2	12.4	N	N		Glenvar substation
Triangle Road	24.0	19.4	20.3	20.8	21.3	21.8	22.3	22.9	23.5	24.1	24.7	25.4	26.1	N	Y		
Victoria	46.1	24.2	25.6	26.1	26.8	27.4	28.1	28.8	29.4	30.0	30.7	31.3	32.0	N-1	Y		Sufficient 11kV backstop capacity
Waiake	15.0	9.7	9.7	9.8	9.9	10.0	10.2	10.3	10.4	10.5	10.7	10.8	10.9	N	Y		
Waiheke	29.9	10.2	10.1	10.3	10.5	10.7	10.9	11.1	11.3	11.5	11.7	12.0	12.2	N-1	Y		
Waikaukau	9.0	7.2	6.9	7.0	7.1	7.2	7.3	7.5	7.6	7.7	7.9	8.0	8.2	N	Y		

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Waimauku	8.0	6.2	6.9	7.1	7.2	7.4	7.6	7.7	7.9	8.1	8.2	8.4	8.6	N-1	N	2019	Second transformer
Wairau	32.0	17.8	16.8	17.1	17.2	17.4	17.6	17.7	17.9	18.1	18.3	18.4	18.6	N	Y		
Warkworth	27.0	17.4	18.4	18.6	18.8	19.1	19.3	19.6	19.8	20.1	20.4	20.6	20.9	N-1	Y		
Wellsford	18.0	7.4	8.1	8.2	8.3	8.4	8.5	8.7	8.8	8.9	9.0	9.1	9.3	N-1	Y		
Westfield	63.4	31.0	30.7	31.2	31.6	32.1	32.6	33.0	33.4	33.8	34.2	34.7	35.1	N-1	Y		
White Swan	48.9	32.2	24.8	25.1	25.3	25.6	25.9	26.2	26.4	26.7	27.0	27.2	27.5	N-1	Y		
Wiri	69.8	41.2	44.0	45.4	46.8	48.2	49.8	51.3	52.8	54.2	55.7	57.3	58.9	N-1	Y		
Woodford	16.0	10.8	10.6	10.8	11.0	11.1	11.3	11.5	11.6	11.8	12.0	12.2	12.4	N	Y		

Table 5-6 : Winter peak demand projection for the bulk supply substations and zone substations for the Northern and Southern regions

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Atkinson Rd	24.0	10.4	10.2	11.1	12	13	14.1	15.2	15.8	16.3	16.9	17.4	18	N-1	Y		
Auckland Airport	58.6	16.4	19.4	25.2	31.1	33.3	35.5	37.8	39.9	43	46	48	50	N-1	Y	2011	Customer substation, managed by customer
Auckland Hospital	8.0	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	N	Y		Sufficient 11kV backstop capacity
Avondale	44.0	17.6	19	20.3	21.7	23.3	24.9	26.6	26.9	27.2	27.5	27.8	28.2	N-1	Y		
Bairds	48.0	16.8	17.8	18.5	19.3	20.2	21.1	22.1	22.5	23	23	24	24	N-1	Y		
Balmain	12.0	4.7	4.7	5	5.4	5.9	6.4	6.9	7.1	7.4	7.6	7.9	8.1	N	Y		
Balmoral	16.8	10.4	10.9	11.8	12.7	13.8	14.9	16.2	16.3	16.4	16.5	16.6	16.7	N-1	Y		
Belmont	28.0	6.5	6.7	7.1	7.5	7.9	8.4	8.9	9.1	9.3	9.5	9.7	9.9	N-1	Y		
Birkdale	30.0	13.5	12.9	13.8	14.8	15.9	17	18.3	18.8	19.3	19.8	20.4	20.9	N-1	Y		
Brickworks	13.0	6.6	6.8	7.3	7.6	7.9	8.3	8.7	8.9	9.1	9.3	9.6	9.8	N	Y	2019	
Browns Bay	28.0	7.9	7.8	8.5	9.3	10.1	11.1	12.1	12.7	13.2	13.8	14.5	15.1	N-1	Y		
Bush Road	42.0	25.2	27	28.3	29.6	30.9	32.3	33.8	35	36.3	37.6	38.9	40.3	N	Y	2016	Greenhithe substation
Carbine	35.4	24.8	20.1	20.5	21	21.4	21.9	22.4	22.7	23	23.3	23.6	23.9	N-1	Y		
Chevalier	15.5	9.1	10.1	10.9	11.7	12.6	13.6	14.7	14.8	15	15.2	15.3	15.5	N-1	Y		
Clevedon	6.0	1.9	2	2.3	2.5	2.8	3.2	3.5	3.6	4	4	4	4	N	Y		
Coatesville	12.0	5.1	5.3	5.7	6.1	6.6	7.2	7.8	8.1	8.3	8.7	9	9.3	N	Y	2019	Second transformer
Drive	35.1	18.1	16.7	17.7	18.9	20.2	21.7	23.3	23.7	24	24.4	24.5	24.7	N-1	Y		
EastCoast Rd	24.0	10.5	10.3	11.1	11.9	12.8	13.8	14.8	15.3	15.9	16.4	17	17.6	N	Y	2016	Rosedale substation
East Tamaki	46.9	15	16.7	16.9	17.1	17.3	17.5	17.7	17.9	18	18	19	19	N-1	Y		
Forrest Hill	38.0	7.1	5	5.4	5.8	6.3	6.9	7.4	7.7	7.9	8.1	8.4	8.7	N-1	Y		
Freemans Bay	36.0	16	17.7	18.3	19	20.2	21.9	23.1	23.5	23.9	24.3	24.7	25	N-1	Y		
Glen Innes	12.0	10.4	6.3	6.8	7.4	8.3	8.9	9.7	9.8	10	10.1	10.3	10.5	N-1	Y		
Greenmount	52.0	37.7	36.6	38.1	39.6	41.2	43	44.8	45.9	47	48	50	51	N-1	Y		
Gulf Harbour	24.0	2	2.2	2.3	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	N	Y		
Hans	33.6	21.3	20.7	21.6	22.4	23.3	24.3	25.3	25.7	26	27	27	28	N-1	Y	2020	Install 3rd transformer
Hauraki	13.0	5.6	5.7	6.1	6.5	6.8	7.3	7.7	8	8.2	8.5	8.8	9.1	N	Y		
Helensville	18.0	8.5	8.5	9.2	9.9	10.6	11.4	12.3	12.8	13.3	13.8	14.4	14.9	N-1	Y		
Henderson Valley	28.0	18.1	18.9	19.6	20.4	21.2	22	22.9	23.5	24.1	24.7	25.3	25.9	N	Y		

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Highbury	15.0	8.6	8.5	8.9	9.4	9.9	10.5	11.1	11.4	11.7	12.1	12.4	12.7	N	Y	2009	Install second transformer
Hillcrest	48.0	17.6	19.8	20.6	21.6	22.5	23.5	24.6	25.1	25.7	26.3	26.8	27.4	N-1	Y		
Hobson 110/11kV	50.0	30.6	30.6	31.5	33.1	34	25.0	36	36.8	37.6	38.4	39.3	40.2	N	Y		11kV to 22kV conversion
Hobson 22/11kV	30.0	17.7	18.1	18.7	19.3	20	15.0	21.3	21.8	22.3	22.8	23.3	23.9	N	Y		11kV to 22kV conversion
Hobsonville	32.0	12.9	13.2	14	14.9	15.9	16.9	18	18.6	19.2	19.8	20.4	21	N	Y		
Howick	46.1	22	22.8	24.4	26.2	28.1	30.1	32.4	32.6	33	33	33	34	N-1	Y		
James Street	32.0	14.7	14.9	15.8	16.8	17.9	19	20.3	20.8	21.4	22	22.6	23.2	N-1	Y		
Keeling Road	24.0	7.8	8	8.4	8.8	9.2	9.6	10.1	10.3	10.6	10.9	11.2	11.5	N	Y		
Kingsland	44.0	17.9	18.8	19.5	20.2	20.9	22	22.8	23.1	23.4	23.6	23.9	24.2	N-1	Y		
Laingholm	17.0	5	5.6	6	6.5	7.1	7.7	8.4	8.7	9	9.4	9.8	10.2	N-1	Y		
Lichfield	24.0	6.9	6.9	6.9	7.2	7.6	8	8.3	8.7	9	9.4	9.8	10	N-1	Y		
Liverpool	60.0	48	52.9	54.2	50	51.3	52.5	53.8	54.9	56.1	57.2	58.4	59.6	N-1	Y		
Mangere Central	43.0	21.8	19.7	20.8	22	23.4	24.7	26.2	26.9	28	28	29	30	N-1	Y	2015	Transfer load to Mangere West substation
Mangere East	37.1	15.3	18.3	19.8	21.3	23	24.8	26.8	27.5	28	29	30	31	N-1	Y	2016	Transfer load to Mangere West substation
Mangere West	70.7	15.9	15.6	16.1	16.5	17	17.5	18	18.4	19	19	20	20	N-1	Y		
Manly	30.0	12.9	14	15.5	16.7	18.1	19.5	21.1	22	22.9	23.9	24.9	25.9	N-1	Y		
Manukau	72.7	23.4	21.8	23.1	24.5	25.9	27.5	29.2	30.1	31	32	33	34	N-1	Y		
Manurewa	52.9	36.1	34.6	37.1	39.8	42.6	45.8	49.2	50.1	51	52	53	54	N-1	Y	2015	Transfer load to Clendon substation
Maraetai	24.0	4	1.7	2.3	3	3.8	4.8	5.9	6.1	6	7	7	7	N-1	Y		
McKinnon	48.0	17.8	18.8	19.8	20.8	22	23.2	24.5	25.7	27	28.4	29.8	31.3	N-1	Y		
Mcleod Road	16.0	7.3	8	8.5	8.9	9.4	10	10.5	10.8	11.1	11.4	11.7	11.9	N	Y	2019	
McNab	66.0	36.3	41	42	44.1	45.2	46.4	48.5	49.9	50.4	51	51.5	52.1	N-1	Y		
Milford	14.0	6.3	6.1	6.6	7	7.5	8	8.6	8.8	9.1	9.4	9.7	9.9	N	Y	2016	
Mt Albert	9.4	5.6	5.7	6	6.3	6.7	7	7.4	7.5	7.6	7.7	7.8	7.9	N	Y		Sufficient 11kV backstop capacity
Mt Wellington	44.0	22.4	21.3	22.2	23.7	25.4	26.5	27.6	28	28.5	29	29.4	29.9	N-1	Y		Sufficient 11kV backstop capacity
New Lynn	30.0	10.4	10.5	11.2	11.8	12.5	13.3	14.1	14.6	15	15.5	16	16.5	N-1	Y		

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Newmarket	66.0	38.9	37.5	38.6	42.1	47.1	50.2	54.5	57.2	60	62.8	65.6	67.1	N-1	Y	2018	Newmarket South substation
Newton	27.9	17.6	17.2	17.9	18.5	19.2	19.9	20.6	21	21.3	21.6	22	22.3	N	Y		Sufficient 11kV backstop capacity
Ngataringa Bay	14.0	6.3	6.4	6.6	6.8	7	7.2	7.5	7.6	7.7	7.7	7.8	7.9	N	Y		
Northcote	15.0	4.9	4.7	5	5.3	5.7	6.1	6.5	6.6	6.8	7	7.2	7.4	N	Y		
Onehunga	17.9	15.5	12.1	12.5	13	13.6	14.2	14.9	15.1	15.3	15.5	15.7	15.9	N-1	Y		
Orakei	27.4	13.2	11.7	12.8	14.4	16.4	18.1	19.8	20.4	20.6	20.8	21.1	21.3	N-1	Y		Sufficient 11kV backstop capacity
Oratia	15.0	3.2	3.2	3.2	3.4	3.6	3.8	4	4	4	4	4	4	N	Y		
Orewa	30.0	8.2	8.7	9.7	10.9	12.3	13.9	15.8	17.2	18.7	20.5	22.5	24.6	N-1	Y		
Otara	34.8	22	20	22.2	24.6	27.3	30.5	34	36.1	38	40	43	46	N-1	Y	2016	Flatbush substation
Pacific Steel	80.0	53.2	43.3	43.3	43.3	43.3	43.3	43.3	43.3	43	43	43	43				Customer substation, managed by customer
Pakuranga	40.5	16.5	14.3	15.3	16.4	17.6	18.8	20.1	20.3	21	21	21	21	N-1	Y		
Papakura	34.8	17.1	18.7	19.6	20.5	21.6	22.6	23.8	24	24	24	25	25	N-1	Y		
Parnell	16.7	7.5	9.3	9.6	10	10.4	10.7	11.2	11.4	11.6	11.7	11.9	12.1	N-1	Y		
Ponsonby	19.9	8.9	11	11.7	12.4	13.1	14	14.8	14.9	14.9	15	15.1	15.2	N	Y		Upgrade project underway
Quay	48.0	22.7	23.9	24.6	25.4	26.5	28	29.6	30.3	31.1	31.9	32.7	33.6	N-1	Y		
Red Beach	24.0	6.7	6.7	6.7	7.3	7.9	8.6	9.3	9.7	10.1	10.5	11	11.4	N	Y	2016	Second transformer
Remuera	44.0	17.3	15.5	16.6	18.1	19.8	23.4	26.7	27.8	28.8	29.1	29.4	29.6	N-1	Y		Sufficient 11kV backstop capacity
Riverhead	18.0	9.3	9.9	10.5	11.1	11.8	12.5	13.3	13.7	14.2	14.7	15.2	15.7	N	Y		
Rockfield	27.4	14.7	16.8	17.5	20.7	23.9	24.9	25.9	26.2	26.5	26.8	27.1	27.4	N-1	Y		
Rosebank	32.2	19.8	19.2	19.8	20.3	20.9	21.5	22.1	22.3	22.5	22.7	22.9	23.1	N-1	Y		
Sabulite Rd	26.0	11.6	11.7	12.6	13.5	14.5	15.5	16.7	17.2	17.8	18.3	18.9	19.5	N-1	Y		
Sandringham	36.8	13.2	13.3	17.8	18.7	19.7	20.7	21.8	22	22.2	22.4	22.5	22.7	N-1	Y		
Simpson Rd	9.0	3.9	4	4.3	4.7	5.2	5.7	6.2	6.5	6.8	7	7.3	7.7	N	Y		
Snells Beach	9.0	4	4.3	4.6	5	5.4	5.8	6.2	6.4	6.6	6.9	7.1	7.3	N	Y	2016	Sandspit substation
South Howick	39.1	17.3	19.4	20.8	22.2	23.7	25.4	27.2	27.5	28	28	29	29	N-1	Y	2017	Transfer load to Howick substation
Spur Road	14.0	8.9	10.1	11.1	12.2	13.5	14.9	16.4	17.4	18.5	19.7	20.9	22.2	N	Y	2019	
St Heliers	24.8	10.6	11.2	12.1	13	14.1	15.2	16.5	16.6	16.7	16.8	17	17.1	N-1	Y		

Substation	Cyclic Substation Capacity	Actual 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Subtransmission security level in 2009	Meets Vectors security stds (2009)	Year of security breach	Comments
Sunset Road	0.0	15.5	15.9	16.5	17.1	17.8	18.5	19.2	19.6	19.9	20.3	20.7	21.1	N	Y		
Swanson	15.0	8.3	8.4	9.1	9.9	10.7	11.6	12.6	13.2	13.7	14.3	14.8	15.5	N	Y	2016	Ranui and Waitekere substations
Sylvia Park	44.0	10.5	18.6	18.8	20.7	22.2	22.8	23	23.1	23.3	23.4	23.6	23.7	N-1	Y		
Takanini	28.7	14.2	14	14.8	15.6	16.4	17.3	18.3	18.7	19	20	20	20	N-1	Y		
Takapuna	24.0	9.6	9.9	10.1	10.3	10.6	10.8	11.1	11.3	11.5	11.7	12	12.2	N	Y		
Te Atatu	28.0	12	11.7	12.5	13.3	14.2	15.2	16.3	16.7	17.2	17.8	18.3	18.8	N-1	Y		
Te Papapa	38.3	21.8	16.7	16.9	17.6	18.2	18.5	18.8	19	19.2	19.5	19.7	19.9	N-1	Y		
Torbay	13.0	5	4.9	5.3	5.8	6.3	6.9	7.5	7.8	8.1	8.4	8.8	9.1	N	Y	2019	
Triangle Rd	24.0	11.5	12	12.9	13.9	15	16.2	17.5	18.2	19	19.8	20.6	21.5	N-1	Y	2019	
Victoria	40.2	28.4	29.6	30.4	31.3	32.2	33.2	34.1	34.8	35.6	36.3	37.1	37.9	N-1	Y		
Waiake	15.0	5.8	5.7	6.1	6.4	6.8	7.2	7.7	7.9	8.1	8.4	8.6	8.8	N	Y		
Waiheke	29.9	5.7	6.7	7.3	8	8.7	9.5	10.3	10.5	11	11	11	11	N-1	Y		
Waikaukau	9.0	3.9	4.3	4.7	5.1	5.5	6	6.5	6.7	7	7.3	7.5	7.8	N	Y		
Waimauku	8.0	4.7	4.4	4.8	5.2	5.6	6	6.5	6.8	7	7.3	7.6	7.9	N	Y	2019	
Wairau	32.0	14.8	15.3	15.8	16.2	16.7	17.2	17.8	18	18.3	18.6	19	19.3	N-1	Y		
Warkworth	27.0	12.6	13	13.7	14.5	15.3	16.2	17.1	17.6	18.1	18.6	19.1	19.6	N-1	Y		
Wellsford	18.0	6.6	6.7	7	7.3	7.6	7.9	8.2	8.4	8.6	8.8	9	9.2	N-1	Y		
Westfield	46.4	30	29.9	30.5	31.1	31.7	32.3	32.9	33.3	33.7	34.1	34.6	35	N-1	Y		
White Swan	33.8	17.3	14.7	16	17.4	18.8	20.5	22.2	22.5	22.7	22.9	23.1	23.4	N-1	Y		
Wiri	62.9	40.4	43.5	45.3	47.2	49.2	51.3	53.5	55.1	57	58	60	62	N-1	Y	2017	Wiri West substation
Woodford	16.0	8.8	8.8	9.1	9.4	9.8	10.1	10.5	10.7	11	11.2	11.4	11.7	N	Y		

Table 5-7 : Summer peak demand projection for the bulk supply substations and zone substations for the Northern and Southern regions

5.5 Embedded Generation

A number of customers wish to connect their own generation to the distribution network. However, the connection of embedded generation must not inhibit the flexibility of operation of the distribution network by constraining the positioning of network open points. This leads to a potential degradation in network performance in the event of faults on the specific feeder. The connection of large blocks of generation capacity can adversely impact operations particularly where loss of the generation can result in substantial network load transfer requirements. Careful monitoring of total feeder load independent of generation is needed to ensure feeder overloads do not result.

Connecting generation increases fault level. While this is not significant with smaller generation, the connection of large quantities or significantly sized units can have an impact. The 22kV fault level in the Auckland CBD for example is approaching switchgear capacity limits and the connection of further generation could cause these to be exceeded. (In this case this issue will be addressed later this year when two high impedance transformers are installed at Liverpool substation).

The manner in which generation is connected to the network should ensure that there is no risk to the public or our service providers. Parallel operation of generation with the network requires specific safety precautions, to prevent "islanding" or feeding back into isolated parts of the network. These precautions are outlined in the connection procedures contained on Vector's website. These procedures also contain the requirements necessary to meet regulations.

In summary, 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 Vector network;
- Metering equipment installed at embedded generating stations must comply with the requirements of the Electricity Governance Rules; and
- Embedded generation connected to the Vector network must comply with:
    - All relevant regulations and Electrical Codes of Practice;
    - The requirements specified in the Electricity Governance Rules;
    - Vector's Distribution Code; and
    - Any requirements as specified in Vector's Technical Requirements for Connection of Embedded Generation.

5.6 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 major network assets such as lines, cables or transformers.

Non network solutions refer to 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 be 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.

5.6.1 Load Shifting (Non Capacity)

This option allows the transfer of load between adjacent zone substations by moving distribution feeder open points to optimise network performance (utilise diversity to reduce overall demand, improve voltage, reduce losses, enhance security and reliability, etc) or minimise the time to carry out manual field switching in the event of a fault. This activity is generally carried out following a load flow study to understand the consequences of the action. Maintaining sufficient backstop capability to supply customers in accordance with security standards and contracted service levels is the key consideration for this option.

5.6.2 Load Control (Non Capacity)

Ripple control and pilot wire systems are used to manage network demand to defer capex for heavily loaded network feeders and substations. They are also used to reduce local demands during contingency events if necessary. Load control provides an opportunity to reduce peak demand by shifting non-essential load such as water-heating into off-peak periods. Load control offers maximum benefit when capacity constraints are imminent (e.g. a cable is approaching capacity). This generally occurs just prior to reinforcement being required.

Load control has traditionally been used for managing demand at GXPs as a means of deferring reinforcement of the transmission system.

5.6.3 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.

5.6.4 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 do 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.

5.6.5 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 consumers and aggregators to develop viable interruptible load models.

5.6.6 Smart Metering (Non Network)

Programmes have started to replace the largely mechanical 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.

5.6.7 Smart Technologies (Non Network)

Investigations on a number of technologies such as smart appliances, home energy management systems, and smart grids, are ongoing to identify how we can use these technologies to help managing peak demands on the network. (See Section 3 for a more in-depth discussion).

5.6.8 Embedded Generation

Embedded generation generally falls into two categories, viz., those installed within a customer's premises for local standby purpose, or large scale generation embedded within the distribution network for the purpose of exporting electricity into the network (by making use of cheap primary energy). Local generation is generally installed to provide a higher level of security that is offered by the network. The generation capacity is usually less than the customer's demand and is designed to support critical loads until the mains supply is restored.

Since the primary energy source for these units is generally diesel, they are expensive to run and widespread application is therefore unlikely. Opportunities do however exist where they offer an economically viable solution to improving the security standard of a wider area and Vector has developed standards to facilitate these types of connection, and has a team of staff to handle customers' connection requests.

5.6.9 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 the 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.

5.6.10 Energy Substitution (Non Network)

Energy substitution is the option to transfer consumption of 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.

5.6.11 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[31] 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 caused by excessive loading, other solutions such as increasing the size of conductors will need to be carefully considered.

Vector has a number of capacitors and voltage regulators in use on its network and will continue to use 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.

5.6.12 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.

[31] VAR is volt ampere reactive

The application of these alternative technologies is very dependent on the specific circumstance, and needs to be assessed on a case by case basis.

5.6.13 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.

5.7 Network Development Options

Growth solutions may be asset or non-asset based. In evaluating the possible solutions, the following are a selection of the factors considered beyond the normal design criteria, to come to an optimal decision:

- Review the asset capacity rating for currency and accuracy of data;
- Consider possible load transfer to alternative circuits or substations;
- Look for load diversity opportunities (mixing commercial and residential loads sometimes allows for feeder load diversity);
- Utilise dynamic ratings of equipment where load peaks are of short duration;
- Use demand side options such as load management (domestic water heaters, air-conditioning units);
- Use automation to expedite load transfer and increase short term asset capacity;
- Use capacitor banks and voltage regulators to defer network investment in low growth areas;
- 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, e.g. asset replacement, undergrounding, road re-alignment or new road construction activities.

5.8 Network Development Programme

In the sections below, the network development plan for the planning period is discussed. Given the accuracy of information available and advanced planning concluded, planning for the first 12 months is at the most detailed level. The plan for the next four years (2012-2015) is somewhat less detailed, while the plans for the remaining five years is at a high level only.

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 $500,000.

5.8.1 Auckland CBD Supply

Background

At present the Auckland CBD has three bulk supply substations, viz. Hobson, Liverpool and Quay. Liverpool and Quay are both supplied from the Penrose GXP via 110kV cables. Hobson bulk supply is supplied from the Liverpool 110kV bus. The summer and winter load forecasts for the CBD 110kV load supplied from Penrose is shown in the table below. An additional 110kV in-feed also exists from Transpower's Mt Roskill substation to Liverpool.

SUMMER MVA		**Actual**						**Predicted**					
Name	**Capacity**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Penrose 110kV		**219**	**219**	**228**	**240**	**253**	**265**	**276**	**287**	**295**	**303**	**311**	**319**

WINTER MVA		**Actual**						**Predicted**					
Name	**Capacity**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Penrose 110kV		**190**	**200**	**207**	**217**	**228**	**238**	**247**	**257**	**264**	**271**	**278**	**284**

Table 5-8 : Summer and winter load forecasts at Penrose GXP

The three bulk supply substations in the CBD further distribute energy to zone substations in the CBD and fringe areas, viz., Freemans Bay, Victoria, Newton, and Parnell, via 22kV sub-transmission circuits. 22/11kV transformers also exist in the three bulk supply substations to supply the 11kV network that still exists in the CBD area. The table below shows the projected summer forecast load at the three bulk supply substations in the CBD.

Auckland CBD

SUMMER MVA	**Actual**							**Predicted**							
Substation	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2035**	**2045**	**2055**
Hobson	**64.0**	**65.2**	**67.3**	**71.9**	**76.9**	**82.0**	**85.9**	**88.6**	**91.4**	**94.2**	**97.2**	**100.1**	**104.1**	**110.6**	**117.4**	**124.6**
Hobson 110/11kV	30.6	30.6	31.5	33.1	34.0	35.0	36.0	36.8	37.6	38.4	39.3	40.2	41.4	44.0	46.7	49.6
Hobson 22/11kV	17.7	18.1	18.7	19.3	20.0	20.6	21.3	21.8	22.3	22.8	23.3	23.9	24.6	26.1	27.7	29.4
Hobson 22kV distribution	0.0	3.8	3.9	6.0	8.8	11.1	12.4	13.7	15.1	16.5	17.9	19.3	21.0	22.2	23.6	25.1
Freemans Bay 22/11kV	16.0	17.7	18.3	19.0	20.2	21.9	23.1	23.5	23.9	24.3	24.7	25.0	25.8	27.4	29.1	30.9
Liverpool	**102.0**	**108.5**	**112.7**	**116.8**	**121.6**	**125.1**	**129.1**	**135.2**	**137.6**	**140.1**	**142.6**	**145.2**	**149.2**	**158.0**	**167.4**	**177.3**
Liverpool 22/11kV	48.0	52.9	54.2	50.0	51.3	52.5	53.8	54.9	56.1	57.2	58.4	59.6	61.4	65.2	69.2	73.5
Newton 22/11kV	17.6	17.2	17.9	18.5	19.2	19.9	20.6	21.0	21.3	21.6	22.0	22.3	23.0	24.4	26.0	27.6
Victoria 22/11kV	28.4	29.6	30.4	31.3	32.2	33.2	34.1	34.8	35.6	36.3	37.1	37.9	39.0	41.4	44.0	46.7
Liverpool 22kV distribution	6.0	8.2	9.8	16.8	19.0	19.8	21.0	25.3	25.6	26.0	26.3	26.7	27.3	28.9	30.7	32.6
Hospital 22/11kV	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Quay	**35.0**	**35.0**	**36.9**	**39.9**	**42.5**	**45.5**	**48.6**	**50.8**	**52.9**	**55.1**	**57.3**	**59.6**	**62.1**	**65.9**	**70.0**	**74.3**
Parnell 22/11kV	7.5	9.3	9.6	10.0	10.4	10.7	11.2	11.4	11.6	11.7	11.9	12.1	12.4	13.1	13.9	14.8
Quay 22/11kV	22.7	23.9	24.6	25.4	26.5	28.0	29.6	30.3	31.1	31.9	32.7	33.6	34.6	36.7	39.0	41.4
Quay 22kV distribution	10.0	9.9	11.1	13.8	15.5	17.3	19.1	20.8	22.5	24.2	26.0	27.7	29.6	31.3	33.2	35.3
CBD total	**201.0**	**208.7**	**216.8**	**228.6**	**241.0**	**207.0**	**215.0**	**223.8**	**229.0**	**234.4**	**239.8**	**245.3**	**253.4**	**268.6**	**284.8**	**301.9**
Annual growth %	-6.1%	3.8%	3.9%	5.4%	5.4%	-14.1%	3.8%	4.1%	2.3%	2.3%	2.3%	2.3%	0.6%	0.6%	0.6%	0.6%

Table 5-9 : Projected load contributions to the three bulk infeed substations

The security standard for sub-transmission network in the CBD is N-1 no break and N-2, switched, with a restoration target time of two hours. To achieve N-1 security over the longer term planning period the intention is to have three 60MVA transformers at each CBD bulk supply substation, loaded to a maximum of 120MVA. To achieve N-2, switched security, the intention is to have three 22kV cables, each rated at 20MVA, between the 22kV buses of the bulk supply substations to transfer load should a second 60MVA transformer fail.

Furthermore the objective over the medium term is to establish a second 110kV GXP point for the CBD. This and the existing (Penrose) GXP must each be able to supply the full demand of the CBD.

The long term planning model is also to establish a 110kV switchboard at both Hobson and Quay substations and a 110kV ring network between the substations to enable supply of a 110kV bus from an adjacent substation's 110kV bus in the event of failure of a 110kV cable or failure of a GXP to the city.

The second GXP point will be established at Hobson substation as part of Transpower's NAaN project[32]. Hobson GXP point will be able to be supplied from either Penrose or Albany by means of the 220kV cable that will be installed by Transpower between Penrose and Albany GXP substations. The geo-schematic below shows the sub-transmission network in the CBD.

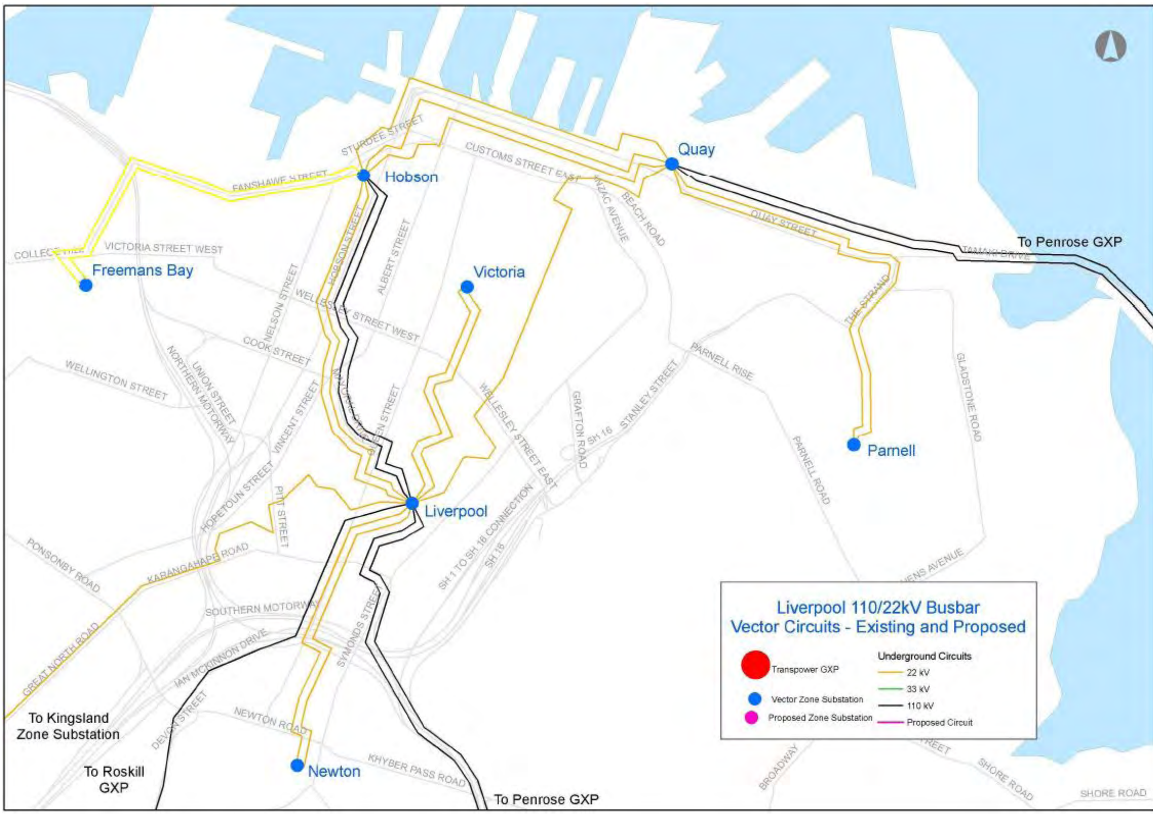


Figure 5-2 : Existing sub-transmission network supplying the CBD

Auckland CBD Distribution Network

A decision was made in 2004 to suspend further development of the 11kV distribution network in the Auckland CBD and to progressively roll out a 22kV distribution network, which will operate alongside the existing 11kV network. Any new connections will be made to the 22kV network as far as practical. Existing 11kV facilities will be progressively transferred over to the 22kV network as and when the 11kV assets reach the end of their economic lives or when additional 11kV capacity is required to cater for demand growth. Over time it is expected the 11kV network will be replaced by the 22kV network as existing substations are progressively upgraded to 22kV. The following diagram indicates the area designated for 22kV distribution development.

[32] Transpower is installing an alternative 220kV supply from Penrose GXP through Auckland to the north, terminating at Albany GXP.

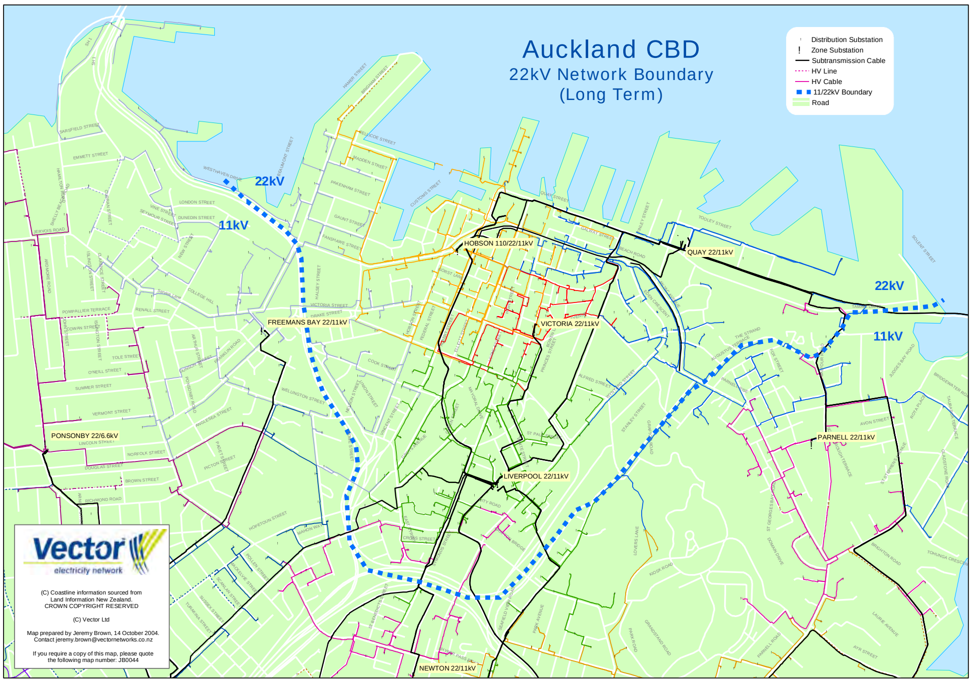


Figure 5-3 : Area designated for 22kV distribution development

Projects – Next 12 Months

- Liverpool to Quay - 110kV cable and third 110/22kV transformer at Quay

  A new 110kV cable rated at 100MVA will be installed during 2010 between Liverpool and Quay substations. A new 60MVA transformer will be installed at Quay substation and connected to the new 110kV cable. Although two 110kV cables exist from Penrose GXP to Quay, these cables are approaching the end of their lives and are limited, due to their age, to capacity of 33MVA each. The 110kV cable and new 60MVA transformer at Quay substation will bring the installed transformer capacity up to 160MVA. With this installation complete the required CBD security levels are expected to be maintained until the new Hobson GXP becomes available.

- Liverpool – replacement of two 110/22kV transformers

  Existing transformers T1 and T2 have reached the end of their technical lives, as indicated through regular insulation condition tests. New 75MVA transformers (with higher impedances than the existing units, to limit the fault level on the Liverpool 22kV bus to appropriate levels) are due for delivery in the second half of 2010, with installation to be complete before the summer peak.

Projects – 2012 to 2015

- Hobson substation – conversion to a GXP

  As noted above, Vector will use the opportunity offered through Transpower's NAaN project to construct a second CBD GXP (220kV/110kV) at Hobson substation. The Transpower works can only occur when the required civil works are in place. Work will start early in this planning period to design, obtain consents and construct the civil works required for the installation of electrical plant by both Transpower and Vector. The installation phase of the electrical plant will take place over the last two years of the four year planning period. The project schedule intends to have the GXP commissioned by May 2014.

- Establishing the Hobson GXP over the next four years entails:
  - The necessary civil works, viz., including plant and transformer rooms, cable tunnels, auxiliary plant rooms, etc. in preparation for the electrical plant and cables;
  - The installation of the 220kV cable by Transpower into Hobson substation using Vector's Penrose to Hobson tunnel and existing easements and ducts from Hobson to Albany GXP;
  - Installation of a 220kV switchgear suite and a 220/110kV transformer by Transpower; and
  - Installation of 110kV switchgear by Vector.
- Quay substation – replacement of 110/22kV transformers

  The two existing 110/22kV transformers are approaching the end of their technical life-spans and tests of the solid insulation have proved that replacement is required in this planning period.
- Liverpool substation – extension of 22kV switchgear

  Extension of the 22kV switchgear is required to provide new 22kV feeders. This is part of the ongoing project to replace the 11kV distribution network in the CBD with a 22kV network.

Projects – Remainder of Planning Period (2016 to 2020)

The following projects are foreseen for the Auckland CBD for the remainder of the planning period:

- Hobson substation - installation of a third 110/22kV transformer to ensure the security level of the substation at N-1;
- Hobson substation - extension of the 22kV switchboard to cater for the conversion of the 11kV network in the CBD to 22kV and to provide additional connection for additional 22kV feeders between CBD bulk substations and GXP substations to provide switched N-2 security;
- Quay substation - extension of the 22kV switchboard to provide feeders for future network reinforcement and to provide CBs for the installation of 22kV interconnectors between bulk substations for switched N-2 security; and
- Liverpool substation - replace the third transformer with a 75MVA transformer.

Non Network and Non Capacity Options

Load control to shift water-heating peak demand is not used extensively in the CBD. Rather than installing load shedding equipment that runs the risk of becoming a stranded asset, smart metering or end-user control devices is intended to be implemented towards the end of this planning period.

Given the importance of the CBD load (predominantly commercial customers), load shedding and load interruption are only used in emergencies and are not considered for managing network demand.

At present PV panels, wind driven micro turbines and solar water heating have very minor, if any, effect as a non network method to manage CBD network demand. The development of smart buildings is seen as a solution that holds potential to manage network demand from the customer side. A prime example of this is the recently completed office/retail building in Karangahape Road that makes extensive use of natural water chilling methods to cool the air.

This building also makes use of solar water heating for building heating, thus reducing the demand of this building considerably.

Embedded generation is used extensively in the CBD but mostly for standby purposes, apart from the CHP generation scheme at Auckland Hospital that produces some electricity for export into the Vector network. Apart from gas, the non availability of other fuels will probably not cause embedded generation to have any significant impact in the CBD as a method to defer capex by Vector.

Fuel swap as a non network method to manage demand is used extensively in the CBD area. Gas is used extensively for cooking in restaurants and hotels and for central heating in some buildings. Gas is also used extensively for water heating in a number of residential complexes and hotels.

Capacitors are used in the CBD to improve the power factor, thus mitigating excess voltage drop and deferring the need for increasing the size of conductors.

5.8.2 Penrose GXP

5.8.2.1 Bulk Supply

Background

Supply is taken from the Penrose 33kV and 22kV bus for local distribution to a number of zone substations in the area surrounding the Penrose GXP. The 33kV bus is supplied by two 220/33kV 160MVA transformers and a third 220/33kV 200MVA transformer. The supply to the 22kV bus is from the 33kV bus via three 33/22kV 45MVA auto transformers. These transformers are all Transpower owned assets. The geo-schematic in Figure 5-4 below shows the existing 110kV, 33kV and 22kV sub-transmission networks supplied from this GXP.

Projects – Next 12 Months

No network or non network expenditure is required.

Projects – 2012 to 2015

No network or non network expenditure is required.

Projects – Remainder of Planning Period (2016 to 2020)

The long term plan is to progressively transfer load from the 22kV bus to the 33kV bus in conjunction with the 22kV asset replacement programme. Future new zone substations will be connected to the 33kV bus with the 22kV network phased out over time.

It is proposed to establish the following new GXP points:

- In the southern area of Newmarket in 2020; and
- In Onehunga South/Southdown area in 2026.

The two GXPs will supply high density commercial/industrial load in the two areas and will relieve the heavily loaded Penrose 33kV GXP.

Non Network and Non Capacity Options

Due to the industrial and commercial nature of the load in this area, load shedding is only used for emergency purposes, apart from in the interspersed residential areas where it is used as necessary.

PV panels, wind driven micro turbines and solar water heating have very minor effect in this area at the moment and its effect as non network solutions is negligible.

Embedded generation is used extensively in the Penrose area but mostly for standby purposes or peak lopping purposes with little impact on Vector's network.

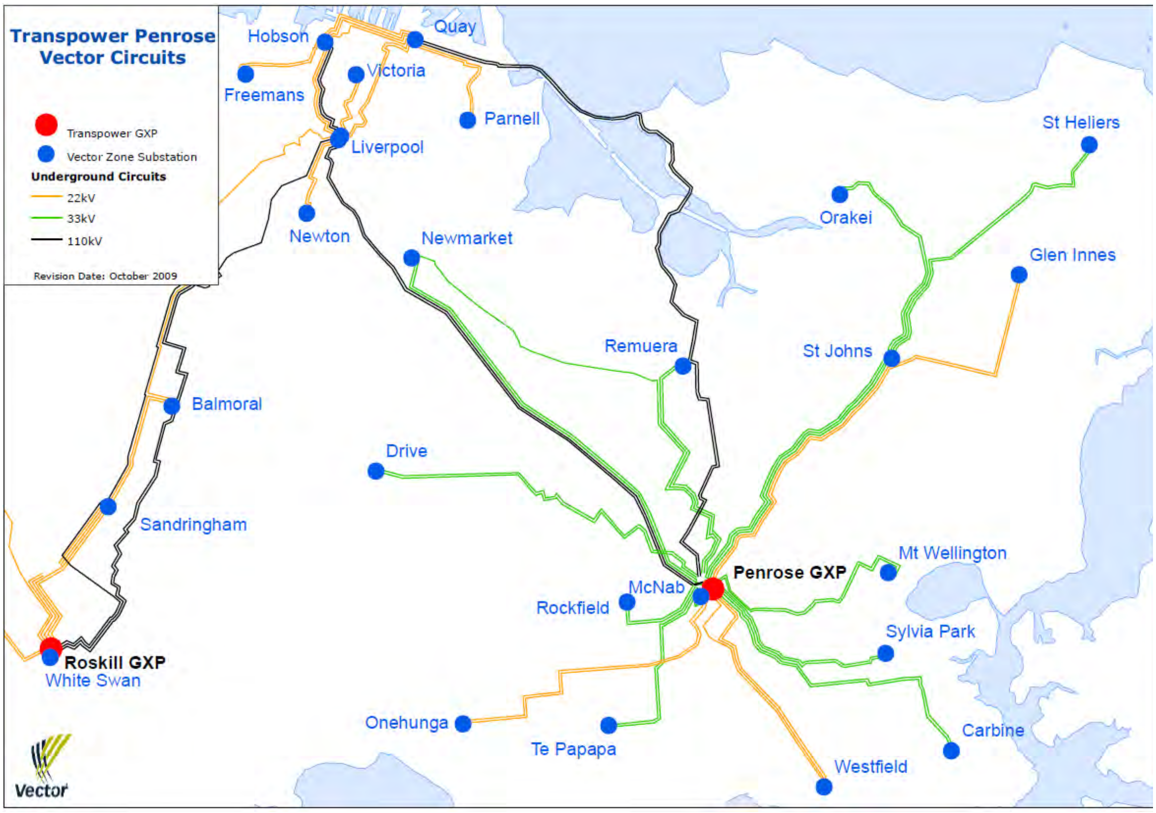


Figure 5-4 : Existing sub-transmission network at Penrose GXP

5.8.2.2 Penrose 22kV Sub-transmission Network

Background

Penrose 22kV GXP supplies three zone substations, viz., Glen Innes, Onehunga, and Westfield. The table below shows the summer and winter load forecasts at the GXP.

SUMMER MVA		Actual						Predicted					
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Penrose 22kV	90	56	48	50	52	54	56	58	58	59	60	61	61

WINTER MVA		Actual						Predicted					
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Penrose 22kV	90	68	55	56	57	58	59	60	61	62	63	63	64

Table 5-10 : Summer and winter load forecasts at Penrose 22kV GXP

Projects – Next 12 Months

A project to establish a new zone substation at Hillsborough is underway and will be completed around October 2010. The new substation will be connected to Roskill 22kV GXP. Refer to Hillsborough substation in Roskill 22kV group. The completion of Hillsborough substation will offload Onehunga substation and address the security shortfall at Onehunga substation that has arisen due to demand growth.

Projects – 2012 to 2015

No network or non network expenditure is required.

Projects – Remainder of Planning Period (2016 to 2020)

No network or non network expenditure is required.

5.8.2.3 Penrose 33kV Sub-transmission Network

Background

Penrose 33kV GXP supplies 11 zone substations, viz, Carbine, Drive, McNab, Mt Wellington, Newmarket, Orakei, Remuera, Rockfield, St Heliers, Te Papapa and Sylvia Park. It also supplies a 33kV switching station at St Johns.

The table below shows the summer and winter load forecasts at the GXP.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Penrose 33kV combined	404	272	275	286	306	328	347	368	377	384	391	398	403
Penrose 33kV		216	227	236	254	275	291	310	318	325	331	337	342

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Penrose 33kV combined	418	332	317	321	333	348	359	369	378	386	392	399	404
Penrose 33kV		264	262	265	276	290	300	309	317	324	330	335	340

Note: combined load including load at 22kV

5-11 : Summer and winter load forecasts at Penrose 33kV GXP

Projects – Next 12 Months

- St Johns substation

  The residential development of Mt Wellington Quarry will add between 7MVA and 10MVA extra load over the next seven to ten years. The four existing substations adjacent to Quarry, Glen Innes, Mt Wellington, Orakei and Remuera do not have sufficient capacity or adequate security to supply this new development. A new substation at St Johns will meet the load growth due to development in Mt Wellington Quarry, and allow load transfer from the adjacent substations to improve their security margin.

  A project has been approved by the Board to establish a new substation at the existing St Johns switching station site. The substation will be equipped with two 33/11kV 20MVA power transformers connecting to 33kV switchboard, and one 11kV board. 11kV cables have been installed to supply the area from the new substation. The new substation is scheduled to be commissioned in mid 2010.

  Vector considered establishing the new substation with a single 20MVA transformer instead of the two proposed. This option is lower cost and provides a staged development permitting the installation of the second transformer at a later date. The load at the completion of the development warranted a dual transformer substation at St Johns but as the development is proceeding at such a rapid rate, it is prudent to install the second transformer at this time.

  Two other options were assessed including the installation of auto-switching schemes and load shedding to mitigate outage risks during fault conditions. Adjacent substations are heavily loaded and adding further load will breach security levels (Orakei: 26MVA on two 14.5MVA transformers, Mt Wellington: 16MVA on two 15MVA transformers, Glen Innes: 24MVA on two 15MVA transformers).

Adding additional load to these substations is not recommended without adding additional capacity.

Projects – 2012 to 2015

- Ellerslie substation

  It is proposed to establish a new substation at Ellerslie. The new substation is required to meet forecast load growth due to the commercial development at Ellerslie racecourse. It will also offload heavily loaded feeders from adjacent substations Remuera, McNab and Drive. The new substation is planned to be commissioned in 2015.

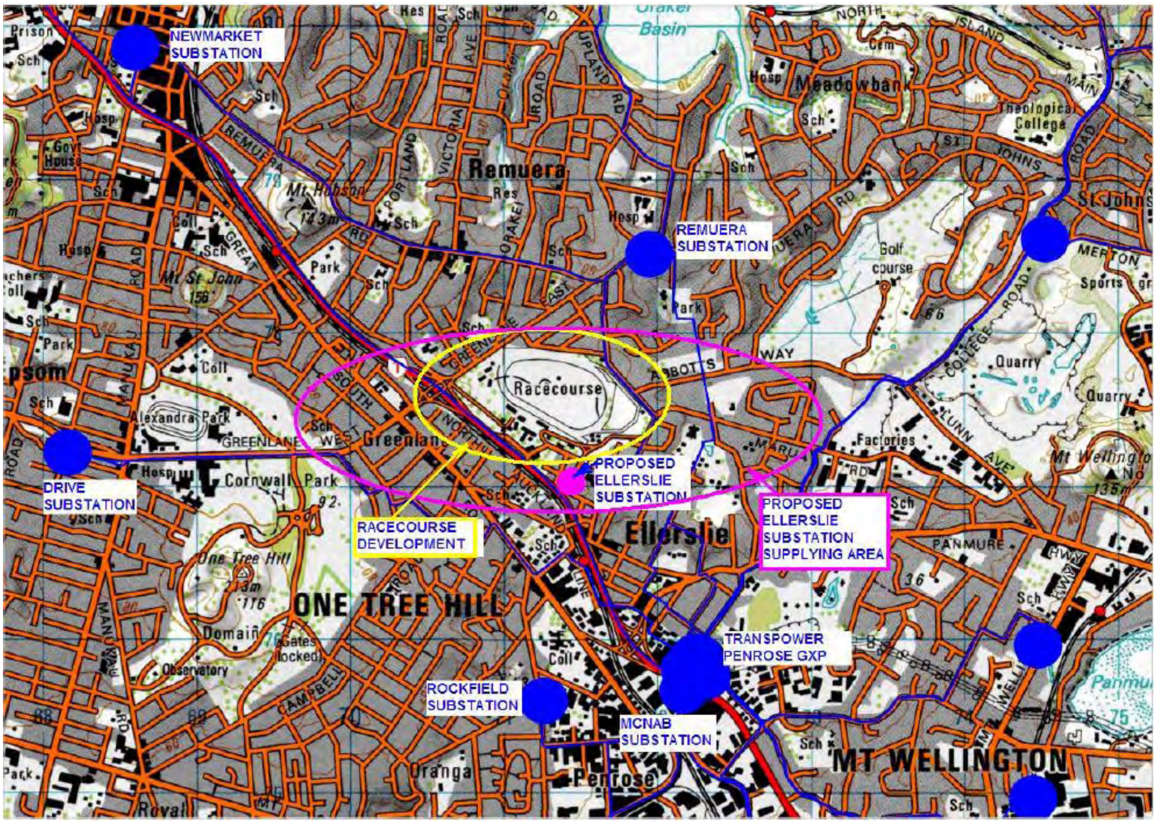


Figure 5-5 : Development area surrounding Ellerslie racecourse

Options considered include the installation of additional feeders from McNab substation. McNab is already a three transformer substation and supplies adjacent industrial areas. Adding additional load onto McNab (43MVA on three 20MVA transformers) will cause this substation to breach security levels. Similarly, at Remuera the load is already high and needs to be offloaded.

Another option is to add further capacity to Remuera, Drive, or Rockfield substations. Remuera, Drive and part of Rockfield's load is residential and adding further capacity will push up fault levels to unacceptable levels. Further substantial upgrading work is required including building alterations to accommodate additional switchgear, replacement of existing switchgear to units with higher current carrying capability, and the installation of long sub-transmission and distribution cables to take the supply to the substations and return it to Ellerslie. Overall these options are more costly compared with constructing Ellerslie substation.

- Newmarket South substation

  The existing supply to Newmarket is from a three transformer substation in Gillies Avenue. Current load is 39MVA on three 20MVA transformers. The load has decreased with the progressive relocation of Lion Breweries to Ormiston Road but a combined residential/commercial development is planned on this site. Newmarket substation is ideally suited to supply this site.

  A customer has indicated further load increases for its shopping mall at the south end of Newmarket and it is unlikely Newmarket substation will have the capacity to meet the increased load. Feeders from adjacent Remuera and Drive substations are heavily loaded and while an option remains to install additional feeders from these two substations there is insufficient capacity in these substations to meet the additional demand.

  A new zone substation is proposed at the south end of Newmarket with a commissioning date of 2014. The supply to Newmarket South substation has yet to be finalised but will initially utilise Newmarket's 33kV feeders until capacity constraints dictate an upgrade. Establishing a new GXP at Newmarket South supplied from Penrose 110kV is likely to be the next phase of the plan.

  Alternative options include installing additional feeders from Newmarket to supply the southern commercial area. With Newmarket South substation established, and when the ex-Lion Breweries site is developed, Newmarket will be at its load centre. Newmarket South will offload Remuera and Drive substations and supply the Westfield complex. Installing additional feeders from Newmarket to pick up load distant from the load centre is technically and financially inefficient.

  Installing additional capacity at Remuera, Drive, or Rockfield substations is an option. The issues with this option have been described under the Ellerslie substation proposal above and the same arguments are applicable in this case.

- St Johns - additional 33kV circuit

  St Johns substation is a 33kV switching station supplying St Johns, Orakei, Glen Innes and St Heliers substations. Load increases on these substations are causing security constraints on the Penrose to St Johns 33kV feeder circuits. An additional 33kV circuit from Penrose 33kV GXP to St Johns switching station is required to relieve this constraint. The cable route will be investigated in conjunction with Auckland City Council's Tamaki development. The new circuit is planned to be commissioned in 2014.

Alternatives considered include the transfer of load away from the site but geography and distances make this financially inefficient.

Projects – Remainder of Planning Period (2016 to 2020)

No network or non network expenditure required.

Non Network and Non Capacity Options

Load control has been extensively used in residential areas in this group to shift water heating peak in winter. The possibilities of smart metering or home control hubs towards the end of this planning period could add more opportunities to control peak load.

Capacitor banks have been installed in the substations predominantly supplying industrial areas. This reduces the reactive power drawn from GXPs which therefore defers requirement of reinforcing sub-transmission circuits.

It is proposed to install load shedding, fast switching and/or automatic load transfer schemes at selected substations and feeders to mitigate the impact of loss of supply under contingency condition.

Other non network options such as distributed generation, PV panels, wind micro turbine and solar power, are not extensively used in this group due to present high cost and minor effect compared to other options at this stage.

5.8.3 Roskill GXP

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 the 110kV bus at Liverpool in the CBD. Since 2007, the normal supply to Liverpool 110kV bus has been changed to Penrose GXP and Roskill GXP is a standby supply.

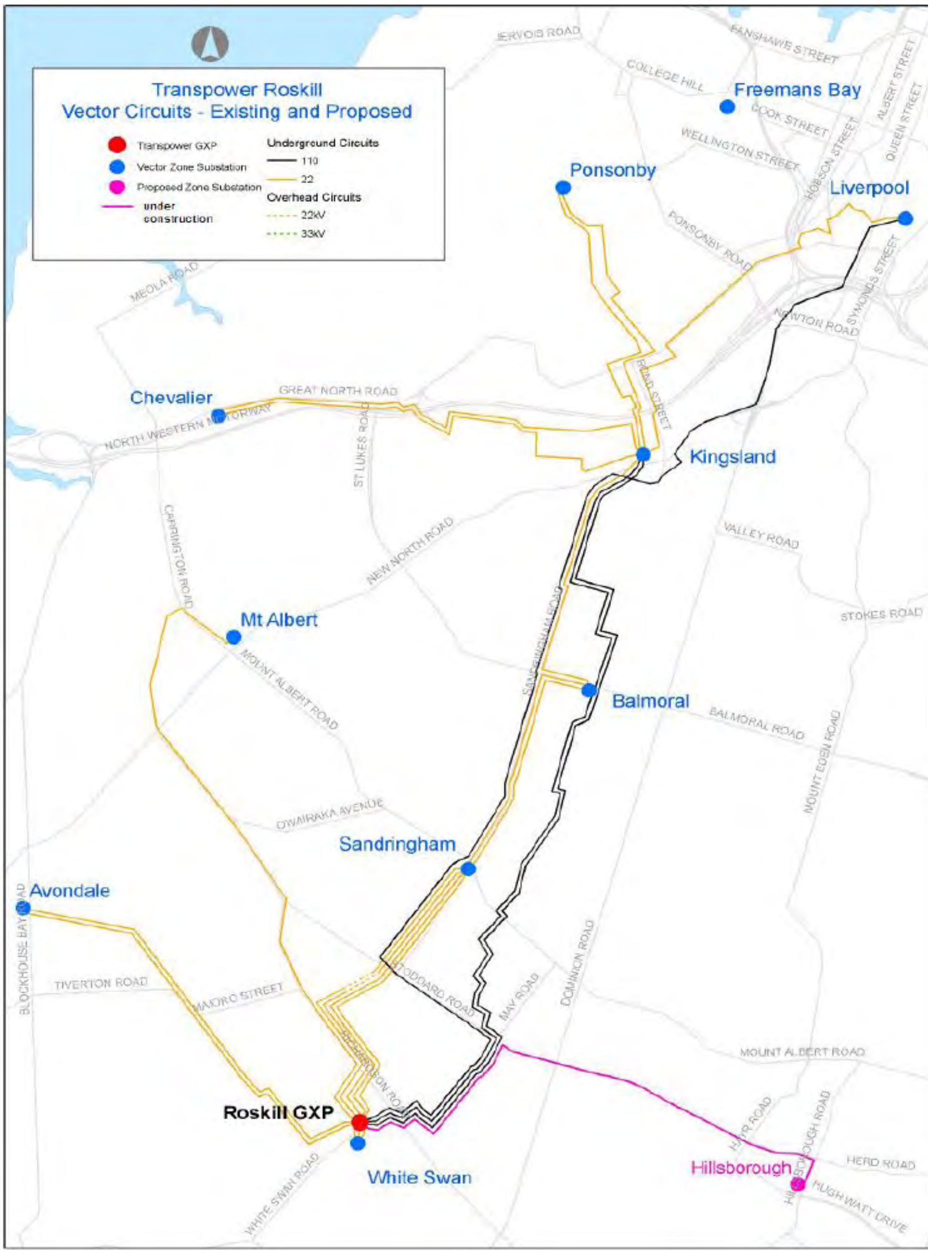


Figure 5-6 : Existing sub-transmission network at Roskill GXP

5.8.3.1 Kingsland Sub-transmission Network

Background

There are two 110/22kV 60MVA transformers and two 22/11kV 20MVA transformers installed at this substation. The two 22/11kV transformers are connected to a 22kV switchboard supplied by the 110/22kV transformers. Two zone substations, Chevalier and Ponsonby, are also connected to Kingsland 22kV switchboard via 22kV cables. The table below shows the summer and winter load forecasts at the substation 22kV switchboard.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Kingsland 22kV	84.0	35.5	37.9	39.9	42.0	44.3	47.0	49.6	50.1	50.5	51.0	51.5	52.0

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Kingsland 22kV	90.0	41	43	43	43	44	45	45	45	46	46	47	47

Table 5-12 : Summer and winter load forecasts at Kingsland substation 22kV switchboard

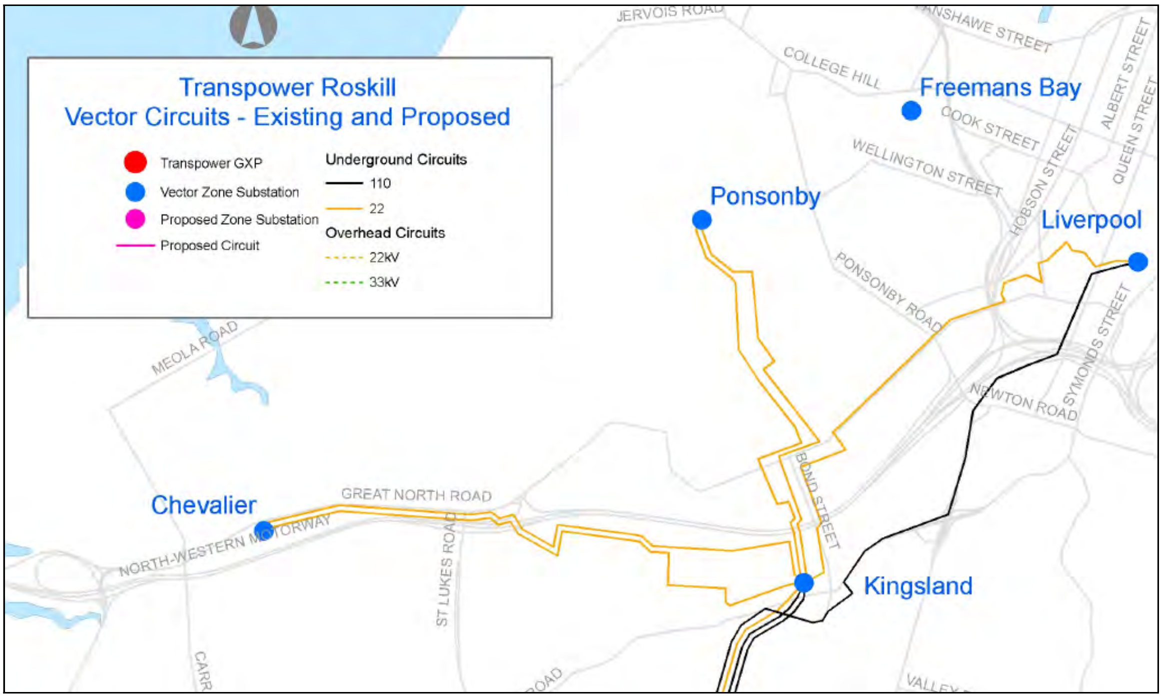


Figure 5-7 : Existing sub-transmission network connecting to Kingsland 110/22kV substation

Projects – Next 12 Months

- Chevalier and Ponsonby upgrade

  A 6.6kV distribution network supplies the Chevalier and Ponsonby area. Load analysis shows there is a security shortfall developing on this network. As this is the last remaining 6.6kV network within Vectors distribution area, a project has been initiated to upgrade the 6.6kV network to 11kV. The project involves replacing the existing 6.6kV rated assets with 11kV equipment including a power transformer at Chevalier substation and approximately 80 distribution transformers. The 6.6kV equipment is approaching end of life and due for replacement. Project completion is scheduled in 2010.

The option to reinforce and maintain the existing network at 6.6kV was considered as an alternative. However, load growth was necessitating additional feeders and therefore additional switchgear. Equivalent capacity feeders at 6.6kV are more costly than 11kV. Furthermore, the age of the network was driving imminent replacement programmes. The network was always considered a candidate for an upgrade to 11kV so over time, equipment installed on the network was 11kV rated. Due to the fact this was a small network embedded within a surrounding 11kV network supply security at 6.6kV was always going to be problematic. Considering all this the prudent decision was to upgrade to 11kV.

- Chevalier second transformer

The New Zealand Transport Authority (NZTA) has requested a construction supply of approximately 4MVA for the north portal of the Waterview tunnel. This additional demand will breach security levels at this substation. It is therefore proposed to install a second 22/11kV transformer at Chevalier substation and a new 11kV feeder to supply the construction load. This project is planned to be commissioned in the third quarter of 2011.

For the permanent supply, NZTA has requested diversity by supplying the north and south portals from differing GXP's. The south portal will be supplied from Roskill GXP while the north portal will be supplied from Hepburn Road GXP.

Once the northern portal permanent supply is connected the construction capacity at Chevalier will become available. This capacity will be used to support load from Mt Albert and Rosebank substations, deferring imminent upgrades at these two substations.

This project is one of the several projects in the long term plan for Waterview tunnel area. Refer to the Waterview tunnel supply project below for details.

Projects – 2012 to 2015

- Waterview tunnel supply

NZTA plan to build a road tunnel on SH20 between Waterview and Sandringham. Both construction and permanent power supplies are required as follows.

North Portal Supply		
Construction	Load	3.5MVA
	Timeframe	Q3 2011 to 2015
Permanent	Load	4.0MVA
	Timeframe	2015
	Security of Supply	N-1 with auto switching
	GXP	Hepburn or Henderson

South Portal Supply		
Construction	Load	3.0MVA
	Timeframe	Q3 2011 to 2015
Permanent	Load	4.0MVA
	Timeframe	2015
	Security of supply	N-1 with auto switching
	GXP	Roskill

Table 5-13 : Power supplies required at Waterview tunnel

There is insufficient existing supply capacity within the network to supply the tunnel load during the construction phase or permanently. Reinforcement is therefore proposed.

Options have been investigated, considering potential synergies among various projects planned in the wider area, to find an optimal and cost efficient solution for the long term. The preferred long term plan is outlined below:

- 2012

  Install a second 33-22/11kV 20MVA transformer and two 11kV feeders at Chevalier substation. The additional transformer is required to provide sufficient capacity and security at Chevalier substation to supply the north portal construction load. One of the new feeders will supply the construction load at the north portal temporary site, and the other to offload Avondale substation. This will release spare capacity at Avondale substation to supply construction load at the south portal.

  A new 11kV feeder is required from Avondale substation to the south portal.

Projects – Remainder of Planning Period (2016 to 2020)

- Waterview project
  - 2016

    Install a 33kV circuit from Te Atatu substation to supply the permanent load at the north portal. This circuit will be installed along SH16 during widening of the Te Atatu/Waterview section of the motorway. This circuit will be connected to a single 33/11kV 10MVA transformer to provide the north portal permanent supply.

    The 11kV feeder providing the construction supply to the north portal will be diverted to offload Mt Albert substation therefore deferring reinforcement of sub-transmission capacity at Mt Albert substation.

    A new 11kV feeder from Sandringham substation will provide the permanent supply to the south portal. Note that the construction and permanent power supplies are needed at different locations for the south portal and the Sandringham supply is less costly than extending the Avondale supply.

    A new 33kV switchboard will be installed at Avondale substation and 33kV cables will be installed through the Waterview tunnel from Avondale to Chevalier. The 33kV cable will replace the aged 22kV paper insulated lead cables (PILC) to Chevalier. The timing of the replacement of cables is condition-driven and the project year is provisional at this stage.
  - 2017

    Replace the existing transformer at Mt Albert with a 20MVA 33-22/11kV transformer. The replacement is condition-driven and the project year is provisional at this stage.
  - 2020

    Install a new 33kV circuit from Sandringham substation to Mt Albert substation to increase the capacity of Mt Albert substation.

  Future proofing ducts will be installed during various projects and tunnel construction.

  A number of options were considered particularly around supply options. For the south portal these included:
  - Establish a new substation taking supply from Roskill GXP;

- Establish a new substation taking supply from Sandringham substation 22kV;
- Install a new 33kV feeder from Sandringham substation, operated at 11kV to initially supply the construction load, and then uprated to 22kV to supply the permanent load once construction is completed. The 33kV rated conductors are to ensure Roskill GXP may be uprated to 33kV in the future;
- Install a new 11kV feeder from White Swan substation to the south portal; and
- Install an 11kV feeder from Mt Albert substation to supply the south portal construction load.

For the north portal the options included:

- Install a new 22kV feeder from Chevalier substation to the north portal; and
- Replace Chevalier 22kV PIL cables along existing route.

Each of these options was evaluated and all were less technically and capital efficient than the option proposed. The alternatives either involved more expensive cabling costs or resulted in a substation security breach.

Non Network and Non Capacity Options

Load control has been extensively used in residential areas in this group to shift water heating off peak in winter. The possibilities of smart metering or home control hubs near the end of this planning period could add more opportunities to control peak load.

The other non network options such as capacitor banks, distributed generation, PV panels, wind micro turbine and solar power, are not extensively used in this group due to the high cost and minor effect compared to other options at this stage.

5.8.3.2 Roskill 22kV Sub-transmission Network

Background

Zone substations included in this group are Avondale, Balmoral, Hillsborough (under construction), Mt Albert, Sandringham and White Swan.

The table below shows the summer and winter load forecasts at the GXP.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Roskill 22kV	141	72	76	85	91	98	105	112	113	114	115	116	117

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Roskill 22kV	141	111	121	126	128	129	130	131	133	134	135	136	138

Table 5-14 : Summer and winter load forecasts at Roskill 22kV group GX

Projects – Next 12 Months

- Hillsborough substation

  Organic growth has increased the load on Drive and Onehunga substations such that network security levels are in danger of being breached. Over the past eight years a series of 11kV projects have been implemented to mitigate this increase by redistributing load across Sandringham, White Swan, Drive and Onehunga zone substations. While this has been an effective strategy for deferring major investment, further reinforcement at 11kV is uneconomic. A new substation will provide the capacity needs of this area.

Hillsborough zone substation is under construction and due for completion in 2010. The substation will be equipped with one 33-22/11kV 20MVA transformer initially supplied from the Roskill 22kV bus. The sub-transmission circuit installed between Roskill GXP and Hillsborough substation is rated for 33kV but will operate initially at 22kV. An 11kV switchboard and new 11kV feeders have been installed to supply the area.

Reinforcement was identified as the only practical solution, but there were options around how the substation was to be supplied. The supply was to come from Transpower Roskill as the closest GXP but there were options as to whether it was to be supplied from Roskill GXP or Sandringham substation. While Sandringham substation was closer, therefore lower cabling costs, the disadvantage was that Hillsborough substation was consuming capacity that could be more efficiently used for reinforcing Balmoral or Mt Albert substations. The construction of SH20 between Roskill and Hillsborough allowed the installation of the sub-transmission cable along the cycleway adjacent to the motorway. This was an ideal solution as it avoided disrupting local traffic and ultimately was a more direct route and lower cost than the Sandringham alternative.

Projects – 2012 to 2015

No network or non network expenditure is required.

Projects – Remainder of Planning Period (2016 to 2020)

A second transformer and 33kV circuit is planned to reinforce Hillsborough substation.

A new 33kV circuit is planned to reinforce Mt Albert substation.

Non Network and Non Capacity Options

Load control has been extensively used in residential area in this group to shift the water heating peak in winter. The possibilities of smart metering or home control hubs at the end of this planning period could add more opportunities to control peak load.

The other non network options such as capacitor banks, distributed generation, PV panels, wind micro turbine and solar power, are not extensively used in this group due to current high cost and minor effect compared to other options at this stage.

5.8.4 Albany GXP

5.8.4.1 Albany Sub-transmission Network

Background

The Albany area is the fastest growing area on Auckland's North Shore. The new Westfield shopping centre and other business and residential developments are expected to add 20 to 30MVA over the next five to ten years. While the economic recession has somewhat slowed development, this is anticipated to only be temporary.

Coatesville and Waimauku substations are supplied via circuits 22 and 92 running in parallel to Coatesville, following the installation of 33kV switchgear at Coatesville. As part of this work, the Redvale generation has been swapped from the Silverdale GXP to the Albany 33kV bus, to reduce the number of voltage dips experienced by the generation plant. This has had the effect of increasing the load at Silverdale GXP but there has been no reduction of load at Albany.

It is also proposed to transfer Waimauku from Albany GXP to Henderson GXP at a later stage, depending on the timing of the new 33kV link between Swanson and Waimauku substations. In the very long term, Waimauku will be supplied from the new GXP at Huapai. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Albany 33KV	240.0	103.7	113.8	120.7	129.8	138.3	149.0	159.4	166.2	173.5	181.1	189.1	197.6

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Albany 33KV	320.0	152.8	163.0	166.3	169.7	173.3	177.1	181.1	185.3	189.6	194.0	198.5	203.2

Table 5-15 : Summer and winter load forecasts at Albany 33kV sub-transmission network

As the load around the Albany Basin (such as the new Westfield shopping centre) grows, additional capacity will be required at McKinnon substation. Two new larger cables have been laid from Albany to McKinnon and a second transformer commissioned.

A new substation is planned for Rosedale Road (2014) to reinforce the 11kV network in the area. Negotiations are in progress with North Shore City Council (NSCC) for a site in Rosedale Road adjacent to the generating station. This substation will be supplied from the existing 33kV network.

The site for the new substation at Glenvar Road has now been designated. This substation is required to secure the supply to the Torbay substation and the new Long Bay development.

Greenhithe substation is currently under construction and will enable both Bush Road and James Street substations to be offloaded. While the substation can be supplied from Albany 33kV, because of 33kV circuit constraints out of Albany, it will normally be supplied from Henderson via Hobsonville, until the 220kV reinforcement to Wairau is completed in 2013.

Bush Road substation has some loading constraints on the 11kV feeders, particularly in summer. This will be fully relieved when new substations at Rosedale and/or Albany are commissioned and will be partly relieved by the new Greenhithe substation, due for commissioning in 2010.

Other relatively minor circuit overloading situations are also identified if circuit failures occur during peak demand times. These situations can mostly be solved by rearranging the network configuration through switching.

Additional substations will be required in the area, viz., Greenhithe in 2010, Glenvar 2012, Rosedale in 2014 and Albany in 2020 and in the very long term at Northcross and Albany Heights.

The following geo-schematic diagram shows the proposed supply arrangement in the Albany and Wairau areas.

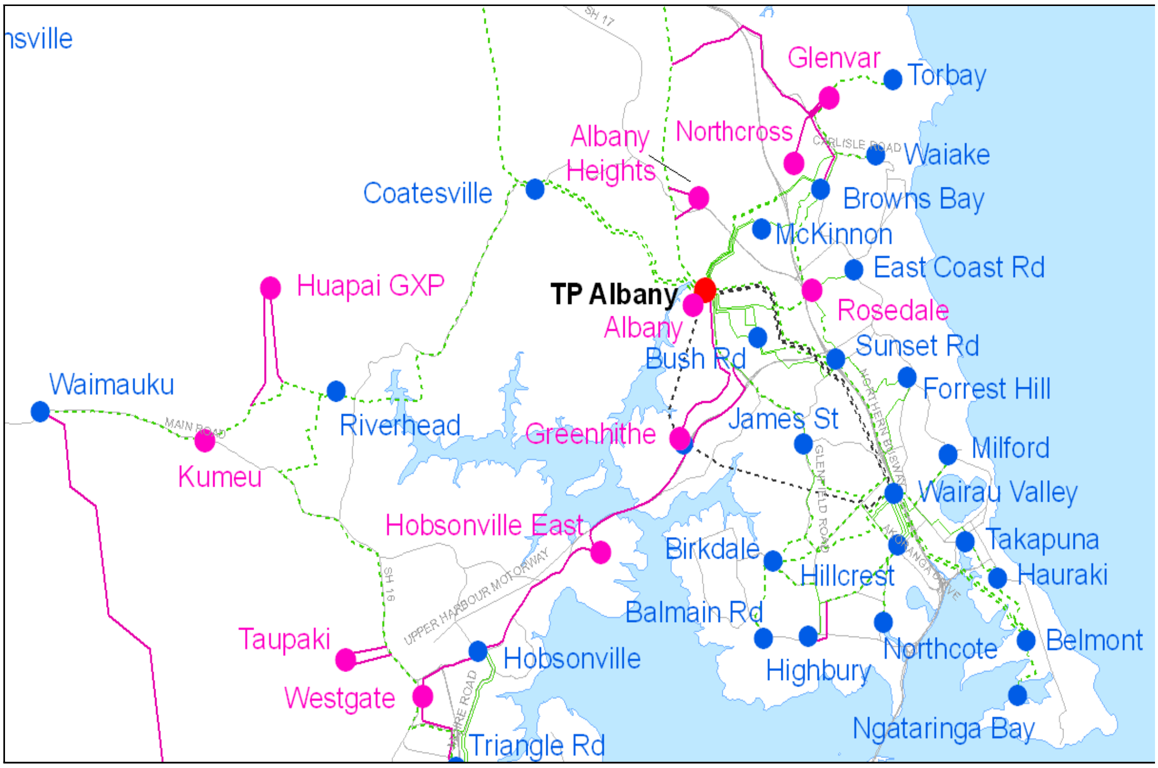


Figure 5-8 : Proposed supply arrangement in the Albany and Wairau areas

Projects – Next 12 Months

- Greenhithe substation

  The Greenhithe area is currently supplied by substations at Bush Road and James Street (see map below). The load on both Bush Road and James Street substations is very high and the two 11kV feeders supplying this area are heavily loaded. Bush Road substation has very little interconnection with adjacent substations and establishing Greenhithe substation will improve this situation.

  The proposed solution was to establish a new zone substation at Greenhithe, on which work commenced during 2010. This has the advantages of offloading and interconnecting Bush Road substation on the 11kV network and supply load at the Hobsonville airbase redevelopment on the other side of the Greenhithe bridge. Work is scheduled for completion during 2011.

- Rosedale substation

  The area around Rosedale Road, between the motorway and East Coast Road, has developed rapidly over the last five years. The bulk of this is business zoned land and the 11kV feeders supplying this area are approaching capacity and need augmenting to provide sufficient backstopping capability. Providing 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 will be purchased during 2011, while construction is set to start in 2012.

The following options were investigated:

- Establish a new zone substation on NSCC reserve land in Rosedale Road. This site provides the ability to interconnect with Bush Road and McKinnon substations and overcome existing shortcomings. 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 is required to provide security of supply to the substation. This can be achieved with a cable from Rosedale Road about 1.5km away but will require a 33kV switching station by the motorway. The cost difference between Rosedale substation which is located adjacent to the 33kV sub-transmission and reinforcing East Coast Road substation is the difference in land acquisition and building construction costs, and the cost of procuring and installing 1.5km of sub-transmission and distribution cables. The least cost option favours the Rosedale substation option, which is also preferred in terms of operational flexibility;
- Increase the capacity at McKinnon substation. McKinnon already has two transformers and the site is fully developed as it is only designed for two transformers;
- Increase the capacity at Bush Road substation. This substation already has two transformers, which is what the site is designed for; and
- Non network options which would potentially resolve the loading issues at Rosedale.

• Glenvar substation

Torbay substation has a single 33/11kV transformer and the transformer is more than 80% loaded. A shortfall of 4MVA 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 a new zone substation at Glenvar. This 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.

The following options were investigated:

- Install a second transformer at Torbay. This is a feasible option and will provide capacity for the proposed new subdivision. However, it 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 as part of this option which provides a backup supply to the Browns Bay 33kV bus; and
- Non network options which would potentially resolve the loading issues at Torbay substation.

• Waimauku substation

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 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. Together with a new 33kV line from Swanson, this will provide adequate capacity and enable Waimauku to be able to backup Helensville substation in emergencies.

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 12.5MVA. The spare capacity is 5.5MVA which reduces to 3.3MVA by 2013 when the shortfall at Waimauku increases to 3.7MVA. The distance between the two substations is 8.5km. To be of 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 a double circuit, 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. While the additional transformer capacity will address immediate capacity constraints, a duplicate 33kV supply from Swanson is needed to repair the security issues. The project requires an additional 33kV breaker at Swanson, and a 33kV switchboard, an extension to the switchroom to accommodate the additional 11kV switchgear and a new transformer bay at Waimauku. The ex-Atkinson Road 10MVA transformer is to be used at this site. This option resolves the issues at Waimauku for some years and has the added benefit of increasing the backstopping to Helensville substation. This will allow the deferment of Kaukapakapa substation to 2015/16;
- 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 33kV line would still be required to mitigate security issues; and
- Non network options - non network options which potentially may resolve the loading constraints on the Waimauku substation are still being investigated.

Projects – 2012 to 2015

It is planned to establish new Rosedale zone substation (see description above).

Projects – Remainder of Planning Period (2016 to 2020)

A new zone substation is planned in the Albany area.

A second 33/11kV transformer is planned for Coatesville substation.

5.8.5 Wairau GXP

Background

Supply to Wairau zone substation is taken from Albany GXP at 110kV to 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 138MVA. The 110kV overhead lines were operating close to their thermal limits (200MVA for the three circuits) but the result of reducing (shifting) the load is that upgrading of the 110kV network is deferred in preference for the establishment of a GXP at Wairau. The 110kV load is shown in the following table.

SUMMER MVA		Actual						Predicted					
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Albany 110KV	200.0	88.1	97.7	101.4	107.5	112.5	119.5	125.3	128.3	131.5	134.8	138.1	141.6

WINTER MVA		Actual						Predicted					
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Albany 110KV	200.0	138.0	138.5	139.9	141.4	143.0	144.5	146.1	147.7	149.4	151.1	152.7	154.5

Table 5-16 : Wairau 110kV summer and winter load forecasts

Common mode failure risk still exists because two of the 110kV circuits are installed on single pole structures but this has been mitigated to some extent by an installation which allows two 110/33kV transformers to be supplied from the single circuit 110kV line. 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. This development will mitigate the risks associated with the 110kV double circuit common mode failure. The GXP transformer can also 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 (three 120MVA transformers).

Projects – Next 12 Months

Commissioning of the GXP point is scheduled for May 2013. During the next 12 month period, the concept design for the development of the site will be firmed up. Development of the concept design will include the 220kV works to be undertaken by Transpower and will be done in conjunction with Transpower.

Projects – 2012 to 2015

The first phase of the GXP project will be clearance of the site with civil and building works and cable access works to follow. The next phase is the replacement of the outdoor 33kV switchgear by Vector with suitably rated indoor 33kV switchgear. Installation of the 220kV switchgear and 220/33kV transformer by Transpower will follow in this planning period.

Projects – Remainder of Planning Period (2016 to 2020)

The second 220/33kV transformer will not be required until the load exceeds 200MVA, i.e. when the 110kV lines are not sufficient to provide N-1 security. This is not expected until 2038 and the installation of the second transformer by Transpower will not occur within this present planning period.

Non Network and Non Capacity Options

Load shedding is only used for emergency purposes in the commercial and industrial zones in the Wairau valley. It is used as a non capacity option to shed load in the residential areas supplied from this zone substation.

PV panels, wind driven micro turbines and solar water heating have only a minor effect in this area at the moment and their impact as non network solutions are negligible.

Smart meters for home energy management are not presently expected to play any significant role in network load management until towards the end of this planning period.

Embedded generation is used but mostly for standby purposes and its effect as a non network method is negligible.

5.8.5.1 Wairau Road Sub-transmission Network

Background

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 circuit to Takapuna was recently fully undergrounded and further analysis is required to determine future reinforcement requirements. The underground cable supplying Takapuna has faulted a number of times and may need to be reinforced with a second cable. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual	Predicted										
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Albany 110KV	200.0	88.1	97.7	101.4	107.5	112.5	119.5	125.3	128.3	131.5	134.8	138.1	141.6

WINTER MVA		Actual	Predicted										
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Albany 110KV	200.0	138.0	138.5	139.9	141.4	143.0	144.5	146.1	147.7	149.4	151.1	152.7	154.5

Table 5-17 : Summer and winter load forecasts at Wairau Road substation

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. This requires some analysis on load sharing and protection issues before being implemented. A second project is planned to install a second transformer at Highbury and this may affect how the 33kV network is configured.

Projects – Next 12 Months

No network or non network expenditure required.

Projects – 2012 to 2015

- Highbury substation

  It is planned to install a second transformer at Highbury substation to reinforce the 11kV network in the Highbury, Birkenhead, Northcote and Birkdale areas. 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.

  The load on Highbury is such that the ability to backstop is becoming an issue and will exceed Vector's security criteria in the next few years. Reinforcing Highbury will allow this substation to offload the adjacent substations of Balmain and Northcote and minimise the costs of reinforcement to the area.

Projects – Remainder of Planning Period (2016 to 2020)

No network or non network expenditure required.

5.8.6 Hepburn Road GXP

5.8.6.1 Hepburn Road Sub-transmission Network

Background

The area supplied by Hepburn GXP comprises mainly residential load with clusters of commercial and industrial load as well as sparsely populated areas such as the Waitakere Ranges. Atkinson Road substation is currently being rebuilt to address load issues. There are several heavily loaded 11kV feeders in the area which require reinforcement.

Parts of the network may be overloaded if outages occur during peak load times. Reinforcements are required for the following circuits:

- The configuration of the 33kV lines into Waikaukau is currently being changed, together with a protection upgrade. This will improve the capacity of these circuits under contingencies; and
- A project is being investigated to connect the Hepburn to Te Atatu circuit into Woodford substation. This will create a 33kV ring through Keeling Road and Henderson Valley and be able to offload the Waikaukau circuits. It also offloads the 33kV circuit to Woodford which can then be used to supply Lincoln substation.

The summer and winter load forecasts are listed below.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hepburn	185.0	94.8	86.8	91.8	97.3	103.1	109.5	116.3	119.6	123.1	126.7	130.4	134.3

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hepburn	325.0	125.8	127.1	129.2	131.1	133.0	135.0	137.1	139.1	141.2	143.3	145.5	147.7

Table 5-18 : Summer and winter load forecasts at Hepburn Road 33kV sub-transmission network

The geo-schematic diagram in Figure 5-9 shows the proposed supply arrangement in the Hepburn area.

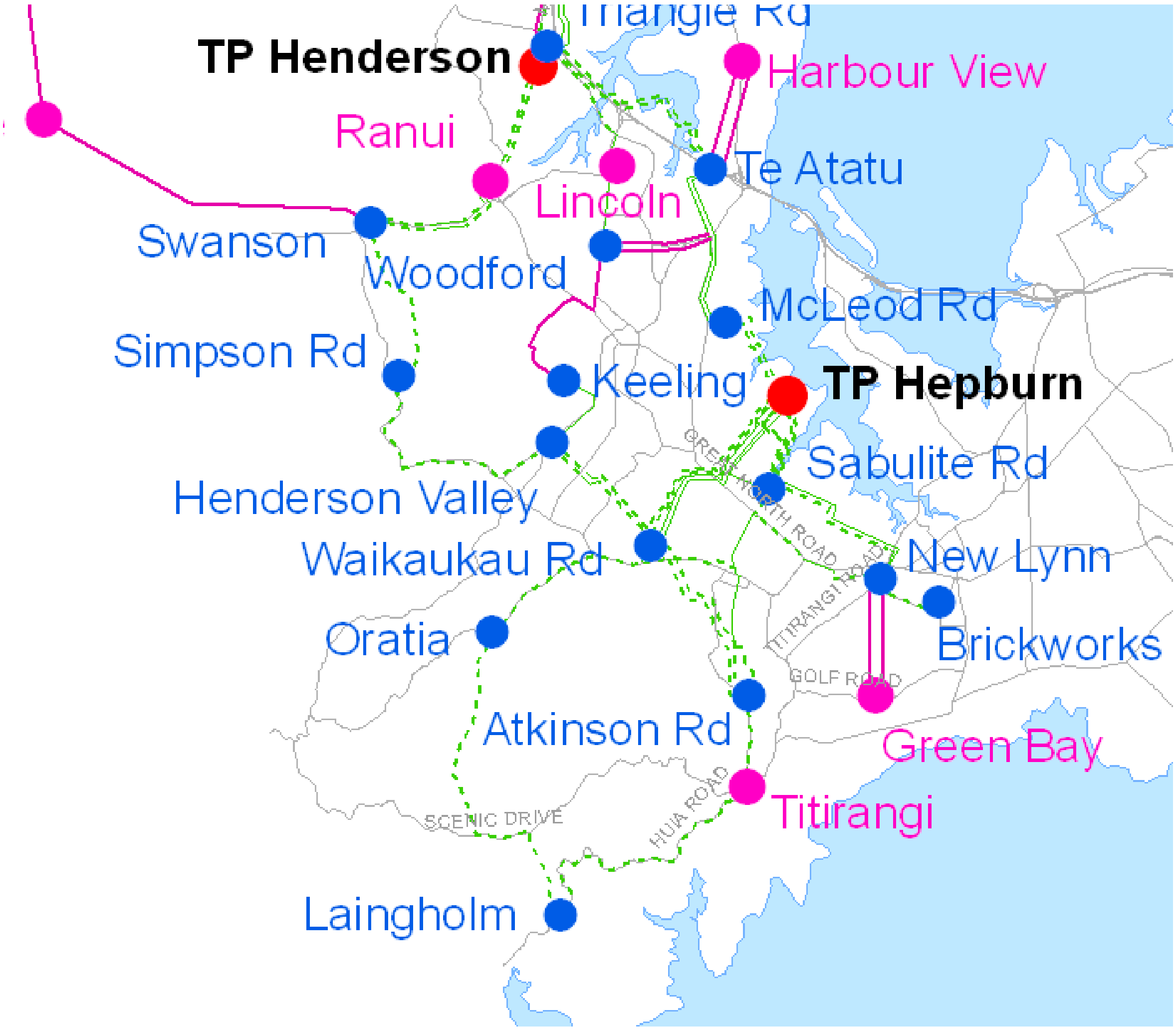


Figure 5-9 : Proposed supply arrangement in the Hepburn area

Projects – Next 12 Months

- Atkinson Road zone substation

  Atkinson Road substation has two 10MVA 33/11kV transformers. The peak load on this substation has been around 18MVA which exceeds the security criteria. While there is adequate 11kV backup supply, the loss of a transformer would result in an outage to customers supplied from this substation. Atkinson Road substation was built more than 50 years ago and has a large outdoor switchyard.

  The proposed solution is to rebuild this substation with a new building, switchgear and larger 20MVA 33/11kV transformers. This is planned to be commissioned by December 2010.

  The following options were considered:

  - Increase capacity at Atkinson Road substation - install two new 20MVA transformers at Atkinson Road, replace the 11kV switchboard in a new switchroom and install additional 11kV feeders to distribute the capacity. This option has the advantage of retiring the existing 11kV switchgear which is nearing end-of-life, removing the outdoor 33kV switchboard and installing larger transformers to meet the security levels. The sub-transmission circuits are adequately rated to supply the extra capacity without reinforcement.

Waikaukau substation is still heavily loaded and will require further offloading in the future. Having additional capacity at Atkinson Road will allow this to happen;

- Third transformer at Atkinson Road substation - install a third 10MVA transformer at Atkinson Road substation. Space limitations on the existing site make this option challenging and, as with the upgrade option, it will require expenditure on a new switchroom, 33kV and 11kV switchgear and the additional transformer. This option will push up fault levels, increase site noise levels and is expected to be a higher cost option than the two transformer alternative;

- Increase the capacity at Laingholm substation - increasing the capacity at Laingholm substation by replacing the two 7.5MVA transformers with new 10MVA units will provide additional capacity but because of its remoteness, it is costly to move this capacity to where it is required at Titirangi. This option would not avoid the additional cost at Atkinson Road substation which still requires switchgear replacement due to age; and

- Establish Titirangi zone substation - a new substation at Titirangi is an option, comprising of a single 10MVA transformer, with space for a second unit as load grows. This option allows 6MVA of load to be transferred from Atkinson Road and Laingholm substations on commissioning, ensuring these substations are below Vector's security limits. As with the previous option, additional expenditure is required to replace the 11kV switchgear at Atkinson Road substation.

The following shows the distribution network in the Atkinson Road/Titirangi area:

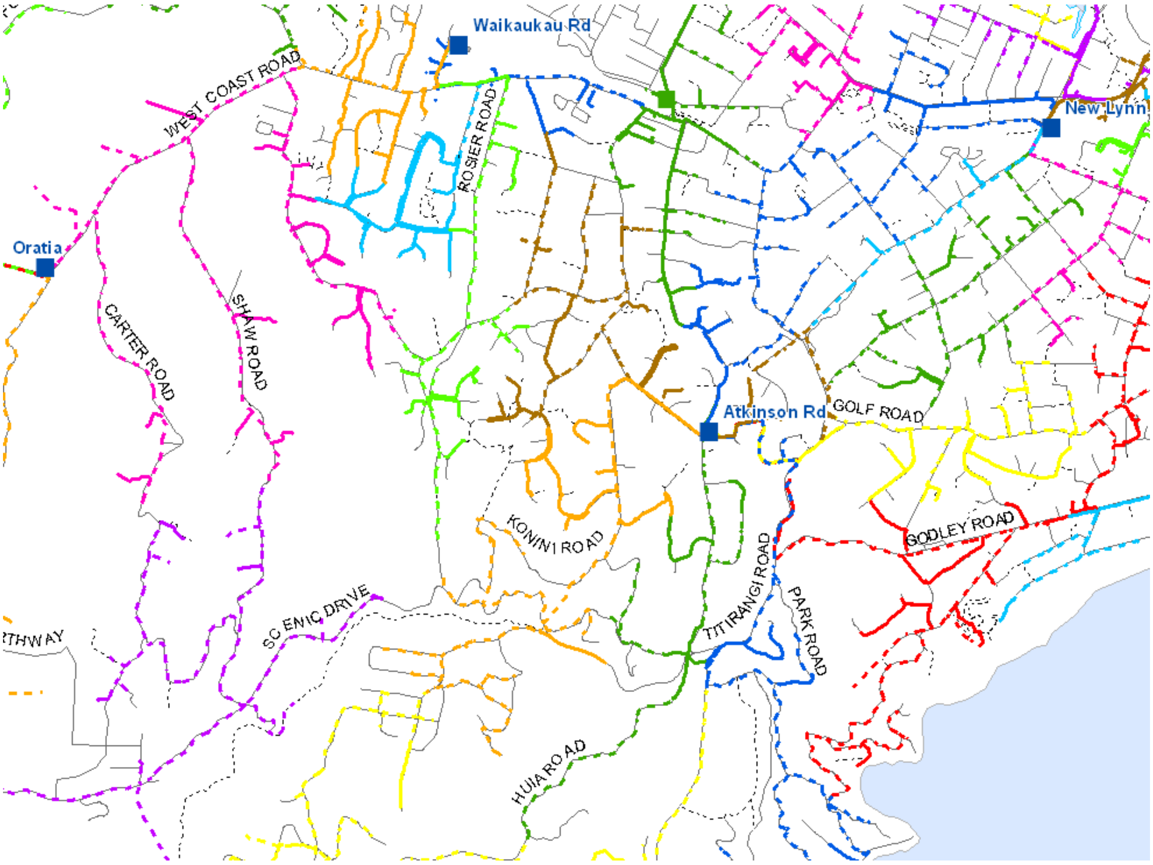


Figure 5-10 : Distribution network in the Atkinson Road/Titirangi area

- Keeling Road to Valley Road 11kV feeder reinforcement

  The Valley Road feeder is currently supplied from Henderson Valley zone substation. This feeder is quite heavily loaded, especially in summer, and requires offloading.

  It is proposed to install two new 11kV feeders from Keeling Road zone substation. This will enable the Valley Road feeder to be cut and turned into Keeling Road substation. This will effectively split the feeder into two and transfer the load from Henderson Valley to Keeling Road substation.

  Options include installing a new 11kV feeder from Henderson Valley substation, replacing undersized 11kV cable to increase the rating of the feeder or installing additional feeders from Keeling Road. Keeling Road substation was designed to take some of the Henderson Valley load as it is closer to the load centre.

Projects – 2012 to 2015

- New Lynn – Totara Avenue 11kV feeder reinforcement

  The Totara Avenue feeder is heavily loaded and the load is expected to exceed the feeder capacity over the next few years, especially during the summer period. Reinforcement options are still being investigated but include transferring load to adjacent feeders, replacing undersized cable with larger cable and installing additional 11kV feeders. As this feeder supplies a large shopping centre, non network options are not viable.

Projects – Remainder of Planning Period (2016 to 2020)

- A new feeder to reinforce Piha from Oratia substation is planned;
- An additional 33/11kV transformer is planned for Keeling Road substation;
- An additional 33/11kV transformer is planned for Woodford substation together with the associated 33kV switchgear and 33kV link to Keeling Road substation; and
- A new Rosebank North substation is planned.

5.8.6.2 Henderson Sub-transmission Networks

Background

The area is mainly residential with clusters of commercial and industrial areas. The reticulation area is bordered by the lightly developed Waitakere Ranges. Six of the substations, Triangle Road, Swanson, Simpson Road, Henderson Valley, McLeod and Woodford, require reinforcement, as the load is approaching the full load capacity of the transformers. There are also several heavily loaded 11kV feeders in the area which require reinforcement.

The installation of NERs at the 33kV side of the 220/33kV transformers at the GXP has resulted in the need for higher voltage rated surge diverters to be installed on the 33kV overhead lines supplied from this substation. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Henderson	240.0	72.7	75.0	79.8	85.1	90.9	97.2	104.0	107.6	111.3	115.1	119.1	123.3

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Henderson	240.0	101.7	104.6	106.5	108.5	110.5	112.6	114.8	116.9	119.2	121.5	123.8	126.2

Table 5-19 : Summer and winter load forecasts at Henderson 33kV sub-transmission network

Riverhead substation is supplied via one circuit from Henderson GXP with a backup supply from Coatesville. Coatesville and Waimauku substations are supplied via circuits 22 and 92 from Albany 33kV GXP. The Henderson and Albany circuits can provide backup to each other during a contingency.

Ranui substation is currently under construction. Additional substations will be required at Westgate in 2015, Waitakere in 2013 and Hobsonville East in 2017. Land in the Hobsonville area has recently been rezoned allowing more intense development.

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 following geo-schematic diagram shows the proposed supply arrangement in the Henderson area.

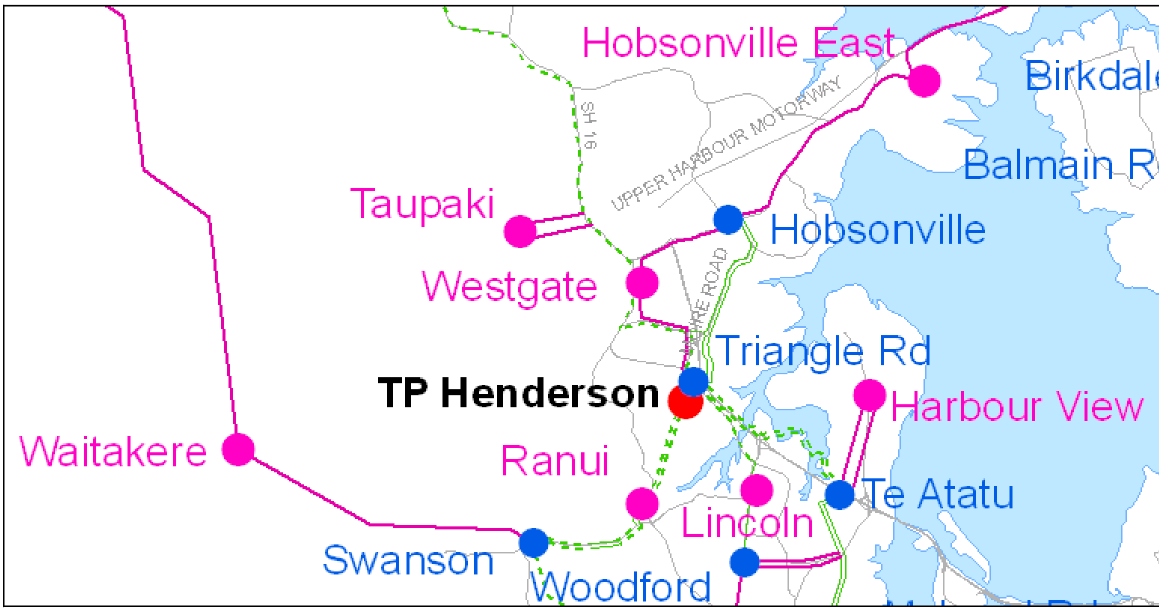


Figure 5-11 : Proposed supply arrangement in the Henderson area

Projects – Next 12 Months

- Ranui zone substation

  The zone substations supplying Ranui, Massey South, Swanson and parts of Henderson are all heavily loaded. Reinforcement is required to maintain the security of supply to the area.

  The Ranui zone substation project is under construction and due to be completed in 2010. This project comprises a single 33/11kV transformer substation and will offload the adjacent zone substations of Swanson, Woodford, Triangle Road, Simpson Road and Keeling Road.

  The options investigated are listed below:

  - Increase the capacity at Triangle Road and Swanson substations

    Install two new 20MVA transformers at each of Triangle Road and Swanson substations, extend the 11kV bus and install additional 11kV feeders to distribute the capacity. The cost of this work is estimated to be $5.5m at Triangle Road and $4.5m at Swanson substation. Compared with establishing a substation at Ranui, this option costs an extra $3m, results in the scrapping of two existing transformers, and the decommissioning and storage of a third transformer until a new site can be found for it, involves more extensive 11 kV network reinforcement, and offers no improvement in diversity of supply. It also results in an immediate 41 MVA capacity increase in the area, whereas Ranui provides a 20 MVA increase now, and a further 20 MVA well beyond the ten year planning horizon, thus providing a better match between capacity increments and demand growth, and hence better asset utilisation;

  - Establish Ranui zone substation

    A new substation at Ranui is proposed, comprising of a single 20MVA transformer, with space for a second unit as load grows. This option allows 11MVA of load to be transferred from Triangle Road, Swanson, Simpson Road and Woodford Avenue substations on commissioning, ensuring these substation loads are below Vector's security standards. The Ranui substation option is a cost effective solution, fits with the long term plan for the area and reduces the length of the 11kV feeders which improves network performance to customers;

  - Reinforce the 11kV network from Triangle Road and Swanson substations

    Gaining additional 11kV capacity from Triangle Road requires installing additional 11kV feeders, necessitating the extension of the 11kV switchboard and the installation of larger capacity transformers. At Swanson substation, adding additional 11kV feeders will instigate a complete switchboard replacement (rather than extending the existing board) and the additional load will initiate a transformer upgrade. Costs are per the first option above; and

  - Reinforce Ranui area via 11kV network from Simpson Road

    Simpson Road currently has a single 7.5MVA transformer loaded to 7MVA. Any attempts to take further load from this substation would initiate a transformer and switchgear upgrade. This substation is too far from Triangle Road substation to allow load transfer and therefore will not address the loading issues at that substation.

Westgate Land Purchase

The Massey North area of Waitakere City 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 will allow the existing Hobsonville substation to supply load further to the east until the Hobsonville East substation is built. This project is to purchase land suitable for the new substation.

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. While this is possible, 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.

Projects – 2012 to 2015

- Westgate zone substation

  This project is to establish new zone substation. This project is discussed above and is due for commissioning during this period.

- Waitakere zone substation

  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; and
  - Establish a new zone substation closer to the load centre.

- Hobsonville – Clark Road 11kV feeder reinforcement

  This project has evolved because of line alterations required to supply the new Greenhithe zone substation currently under construction. The existing Clark Road feeder will be decommissioned as it will be uprated to 33kV. The area currently supplied by this feeder will be supplied from the new Greenhithe zone substation. In the longer term, a new zone substation will be required at Hobsonville East but, to delay this substation, the Clark Road feeder will be reinstated.

The area between Westgate and Hobsonville Airbase is being 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.

Projects – Remainder of Planning Period (2016 to 2020)

- A new zone substation is planned at Kumeu;
- A new zone substation is planned at Hobsonville East; and
- New 20MVA 33/11kV transformers are planned at Te Atatu substation.

5.8.7 Silverdale GXP

Background

Developments along the Hibiscus Coast and the Whangaparaoa Peninsula started as beachside accommodation but have now transformed into permanent residential communities with supporting small commercial and industrial facilities. Load has been growing at a steady pace and this trend is expected to continue as the demand for quality residential properties in Auckland grows. Rodney District Council has recently advised that a large area of rural land (Silverdale North) is to be developed into residential, retail and schools over the next five to ten years.

The Hibiscus Coast is supplied from the Silverdale GXP, commissioned in December 2003. This GXP has two 220/33kV transformers with limited 33kV backup from Albany GXP. The zone substations currently supplied from Silverdale GXP are Spur Road, Orewa, Manly, Red Beach, Gulf Harbour and Helensville. Helensville substation is outside the Hibiscus Coast area and is largely rural in nature. Growth in Helensville is slow but steady.

A second 220/33kV 120MVA transformer has been commissioned at Silverdale GXP (December 2007). The summer and winter load forecasts are listed below.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Silverdale	60.0	43.0	47.9	52.2	56.9	59.9	65.6	71.9	75.9	80.2	84.9	89.9	95.2

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Silverdale	220.0	71.2	65.7	68.1	70.2	72.4	74.7	77.2	79.8	82.5	85.4	88.5	91.8

Table 5-20 : Summer and winter load forecasts at Silverdale sub-transmission network

Red Beach substation was also commissioned in December 2007 and Gulf Harbour in January 2009. There are several other zone substations planned to be supplied from this GXP – these are at Kaukapakapa, Wainui (Silverdale North) and Waiwera. The Kaukapakapa substation is required in 2013 when security at Helensville is anticipated to be breached. However, this could be deferred if Waimauku substation reinforcement project is commissioned before then. There are no firm plans for the Silverdale North (Wainui) substation at this stage but discussions are being held with the developers for a site. An area has been identified for the Waiwera substation but land has not been purchased.

The following geo-schematic diagram shows the proposed supply arrangement in the Silverdale area.

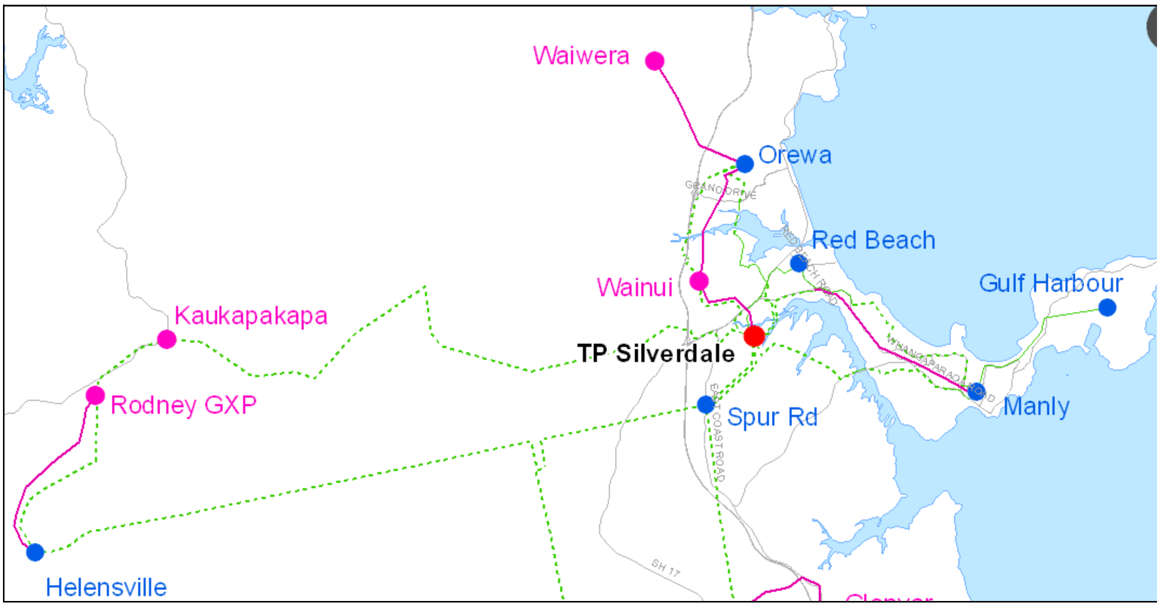


Figure 5-12 : Proposed supply arrangement in the Silverdale area

Projects – Next 12 Months

- Weranui 11kV feeder

  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 allows for future growth in the Waiwera area. 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 is to underbuild the existing Waiwera feeder as far as Weranui Road and then split the feeder into two. This provides immediate relief for the existing feeders and also allows for the future zone substation.

  Reinforcement options are very limited as the area is mainly rural with large areas of bush and the line runs across private property. Constructing a new line across private land would be difficult and there are no vested roads which can be used. There are several large customer loads on this feeder.

Projects – 2012 to 2015

- Red Beach – second 33/11kV transformer

  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. This will allow this substation to continue to support Orewa substation and supply Silverdale North until the Wainui zone substation is commissioned.

- Orewa – third 33kV circuit

  The load flow analysis of the 33kV supply to Orewa indicates that reinforcement of the existing 33kV circuits will be required during this period. The establishment of Red Beach substation has taken some load from Orewa and deferred the reinforcement. It may be possible to transfer additional load onto Red Beach substation once the second transformer is installed and defer this project further. Provision is being made in the Silverdale North subdivision for the new zone substation and 33kV feeder which will eventually extend to Orewa.

- Orewa – Centreway 11kV feeder reinforcement

  The load forecast indicates that during this period, the Centreway feeder will require reinforcement to comply with security criteria. It is expected the load on the Orewa beach front area will intensify and most of this new load will be on the Centreway feeder. Options for reinforcement include a new 11kV feeder from Orewa substation or a new 11kV feeder from Red Beach substation.

Projects – Remainder of Planning Period (2016 to 2020)

It is planned to:

- Reinforce the Wade River feeder (Spur Road substation);
- Establish a new zone substation at Kaukapakapa;
- Reinforce the 33kV network supplying Manly substation;
- Establish a new zone substation at Wainui; and
- Establish a new zone substation at Waiwera.

5.8.8 Wellsford GXP

Background

The Wellsford and Warkworth areas have steadily been developed over the years from a rural area to lifestyle blocks and pockets of residential and light industrial load, as the Northern Motorway has been extended. This will be driven in part by the extension of the Northern Motorway as far as Wellsford over the next ten years.

The Wellsford area is relatively stable with low load growth. The recent closure of the Irwin Industrial Tools factory at Wellsford will likely limit load growth. This company was the largest employer in Wellsford. The Warkworth area is growing much faster and has a sizeable industrial area.

The Warkworth area is currently supplied at 33kV from Wellsford. However, the existing two 33kV lines have reached the point where reinforcement is required to maintain the security of supply to Warkworth substation. A project has been investigated to construct a third 33kV line between Wellsford and Warkworth, which will include allowance for the future substations at Tomarata and Omaha South. However, the existing lines will be upgraded in the short term.

It is planned to construct a southern 33kV ring which would supply the new substations at Sandspit and Warkworth South as well as the existing substation at Snells Beach.

There are three 33kV circuits running from Wellsford GXP to Wellsford substation, two from Wellsford substation to Warkworth substation, and one from Warkworth to Snells Beach substation. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual	Predicted										
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wellsford	60.0	22.0	23.7	25.0	26.4	27.9	29.5	31.2	32.0	32.9	33.8	34.7	35.6

WINTER MVA		Actual	Predicted										
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wellsford	60.0	30.2	26.6	26.9	27.3	27.6	28.0	28.4	28.7	29.1	29.5	29.9	30.3

Table 5-21 : Summer and winter load forecasts at Wellsford sub-transmission network

There are no line CBs at Wellsford and a project is being investigated to replace the outdoor switchgear with indoor CBs. This will improve the security of supply from this substation.

Upon loss of any one of the two circuits between Wellsford substation and Warkworth substation at peak time, overloading is expected to occur on the remaining circuit. One option is that the Dog conductor in circuit 54E (9.7km) is upgraded now and the Cricket conductor in both the circuits (total 20.2km) be upgraded to Cockroach conductor in 2011.

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). A second option is to construct the third 33kV circuit from Wellsford to Warkworth (Whangaripo feeder).

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 bought some time ago and the load has developed further to the south at Matakana. It may be desirable to sell the Omaha South site and buy a new one at Matakana. This 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 bring forward the Tomarata substation. Proposals for developing Te Arai have been scaled back and may not be such a significant load in future. Voltage drop on the 11kV network has been identified as a growing issue and additional 11kV voltage regulators and/or capacitor banks may be required.

A further substation will be required at Sandspit in 2015 to offload and backstop Snells Beach substation. The shortfall is worse in the summer. 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 these substations.

Discussions have been held with Northpower about a 33kV link between Wellsford and their Mangawhai Heads substation but this may not proceed as it will be very expensive to install. A 33kV line will eventually be built to Tomarata for a new zone substation but this is still some years away and it is still some distance from Tomarata to Mangawhai. It is likely that Northpower will reinforce the area from the north.

The geo-schematic diagram in Figure 5-13 shows the proposed supply arrangement in the Wellsford area.

Projects – Next 12 Months

- Warkworth 33kV line reinforcement

  Warkworth is a semi-rural area and the 33kV supply comes from Wellsford, around 15km away. Warkworth 33kV bus supplies the zone substations of Warkworth (17.4MVA) and Snells Beach (5.9MVA), a total load of just over 23MVA. Analysis of the loads on the two 33kV lines indicates overloading of the remaining 33kV circuit under contingency conditions.

  The long term solution for supply to Warkworth is to construct a third 33kV circuit from Wellsford to Warkworth. This allows the new line to supply future substations at Tomarata and Matakana and provides the capacity and security of supply to the Warkworth 33kV bus. The 33kV bus currently supplies Warkworth and Snells Beach substations and will also supply the planned substations at Sandspit and Warkworth South. However, in the short term, it is planned to replace the undersized sections of conductor in the existing line.

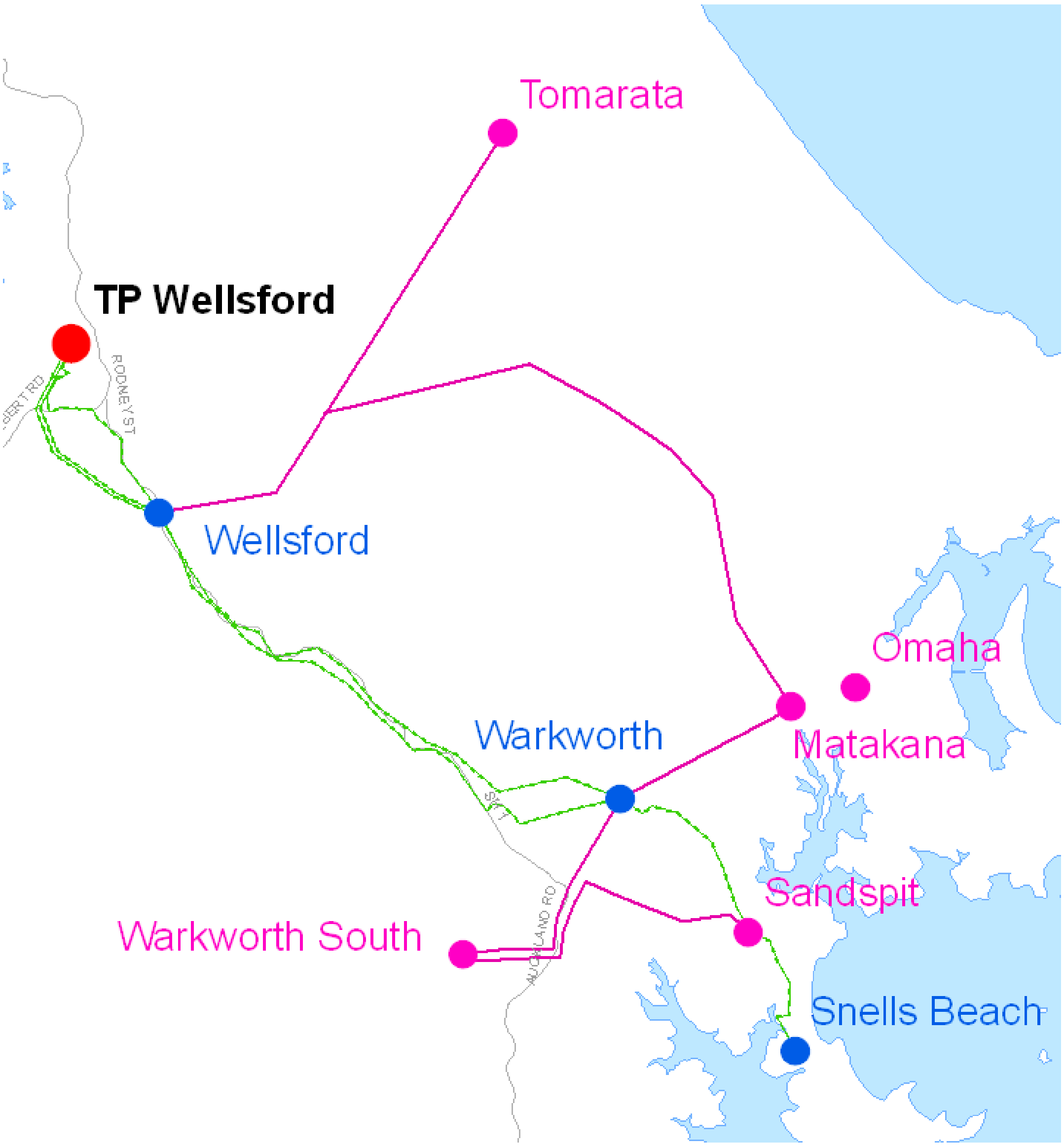


Figure 5-13 : Proposed supply arrangement in the Wellsford area

There are only two options to reinforcing the Warkworth 33kV supply. The first option (and most expensive) is to install a third 33kV line. The second option is to reinforce the existing 33kV lines. This is a much cheaper option and will defer the third 33kV line for some years. Given the continued load growth in this area, non network options are likely to be not economically viable.

Projects – 2012 to 2015

- Whangateau 11kV feeder reinforcement

  The Whangateau 11kV feeder 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, LV is an issue. The first part of the Whangateau feeder is constructed at 33kV to allow for a future zone substation in the area. The solution is a new 11kV feeder from Warkworth (underbuilt on an existing line) and a reconfiguration of the 11kV network to rebalance the loads. Other options such as voltage regulators and capacitor banks will be investigated to see if they can solve any of the supply issues.

- Warkworth South 11kV feeder reinforcement

  The Warkworth South area is on the western side of State Highway 1 and includes the main industrial area of Warkworth. Warkworth substation is about 5km away to the east and the available 11kV feeder capacity into this area is becoming inadequate. Vector has a site for a zone substation in Glenmore Road and plans to eventually build a zone substation to supply this area and offload some of the very long feeders currently supplied from Warkworth substation. 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, non network options are not economically viable.

- Sandspit zone substation

  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. There are two main reinforcement options. The first option is to reinforce the Snells Beach substation with a second transformer. The second option is to construct a new substation at Sandspit and this is the preferred option. This option will allow the Snells Beach load to be offloaded and backstopped with the 33kV supply forming part of the southern 33kV ring including the future Warkworth South substation.

Projects – Remainder of Planning Period (2016-2020)

It is planned to:

- Install a third 33kV line to reinforce Warkworth substation;
- Reinforce the Te Hana 11kV feeder (Wellsford substation);
- Establish a new zone substation at Tomarata supplied from Wellsford GXP; and
- Establish a new zone substation at Warkworth South supplied from Warkworth GXP.

5.8.9 Pakuranga GXP

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). Five zone substations are supplied from Pakuranga including East Tamaki, Greenmount, Howick, Pakuranga and South Howick. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Pakuranga 33kV	136	88.1	89.2	89.2	93.8	98.6	103.8	109.4	115.4	117.2	119.0	120.9	122.8

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Pakuranga 33kV	136	136.2	141.8	143.5	145.3	147.1	148.9	150.8	152.6	154.5	156.4	158.3	160.3

Table 5-22 : Summer and winter load forecasts for Pakuranga 33kV sub-transmission network

The 2009 winter peak demand was 136MVA, reaching the N-1 capacity limit.

Transpower will be upgrading the existing 110kV grid to 220kV as part of the North Island grid upgrade project (NIGUP). The two existing 110/33kV 120MVA transformers will be replaced with two 220/33kV 120MVA transformers by 2011. At the same time an additional 220/33kV 120MVA transformer will be installed to provide a firm 240MVA, N-1 capacity. This will meet the expected long term capacity requirement.

Until the new transformers are installed in 2011, up to 7.3MVA capacity has to be transferred to the adjacent GXPs to meet an N-1 contingency event. This load can be transferred to Otahuhu GXP using two recently installed distribution feeders between Bairds zone substation and East Tamaki zone substation.

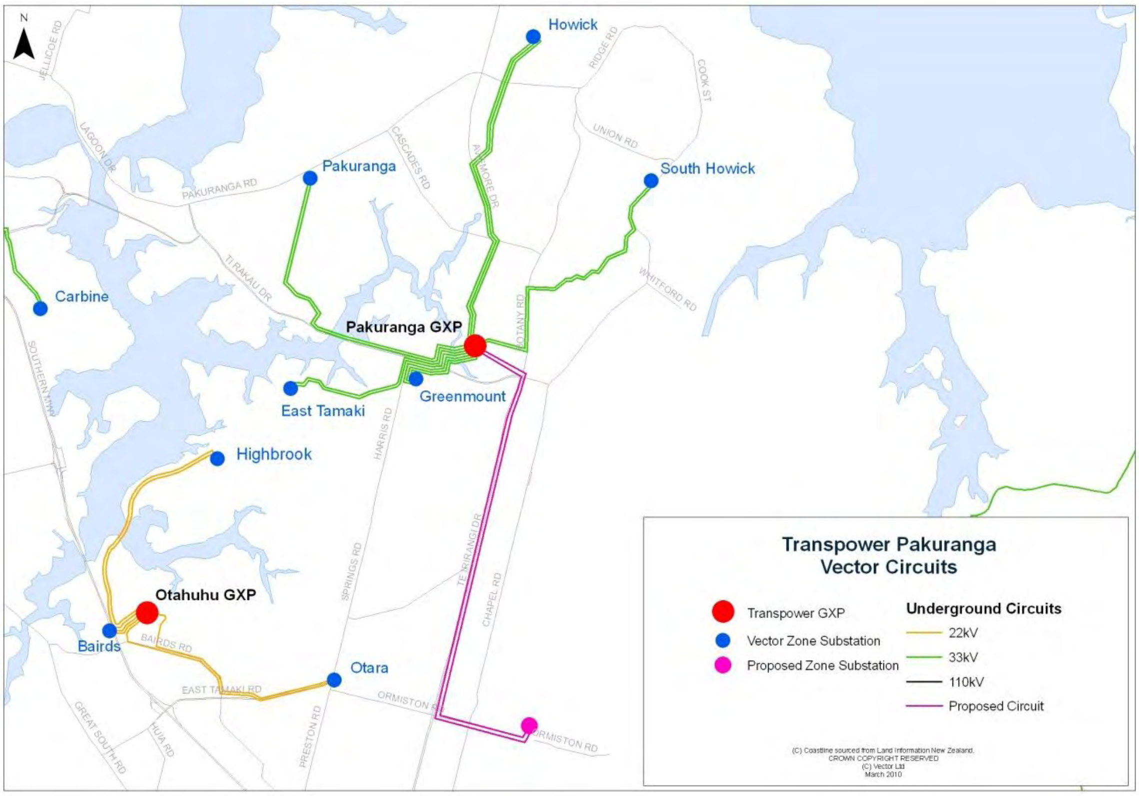


Figure 5-14 : Existing supply arrangement in the Pakuranga area

Projects – Next 12 Months

No network or non network expenditure required.

Projects – 2012 to 2015

No network or non network expenditure required.

Projects – Remainder of Planning Period (2016 to 2020)

It is planned to establish a new zone substation at Flatbush.

5.8.10 Otahuhu GXP

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. Two zone substations are supplied from this Otahuhu 22kV bus, viz., Bairds and Otara. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Otahuhu 22kV	59	44.2	44.9	49.0	53.5	57.9	62.8	67.7	70.5	73.4	76.4	79.7	83.1

WINTER MVA		Actual					Predicted						
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Otahuhu 22kV	59	56.1	58.0	61.1	64.5	67.5	70.7	73.7	76.4	79.3	82.4	85.6	89.0

Table 5-23 : Load forecasts at Otahuhu 22kV sub-transmission network

The 2009 peak demand at this GXP was 56.1MVA. It should be noted that the demand in the area covered by the GXP is also served by an embedded generation plant at Greenmount (typically generating 4MW). Taking this into account, the full peak load in the area in 2009 was 60.1MVA. Demand at the GXP is projected to grow to about 86MVA towards the end of the planning period. The capacity of the two transformers is 100MVA, but its N-1 capacity is restricted due to 22kV incomer cable ratings. Addressing this issue will lift the N-1 capacity to 67/71MVA (summer/winter). The present load projection indicates that the demand on this GXP will exceed 59MVA by about 2011. A transformer upgrade will be required to maintain the security in the area.

The following geo-schematic diagram shows the existing supply arrangement in the Otahuhu area.

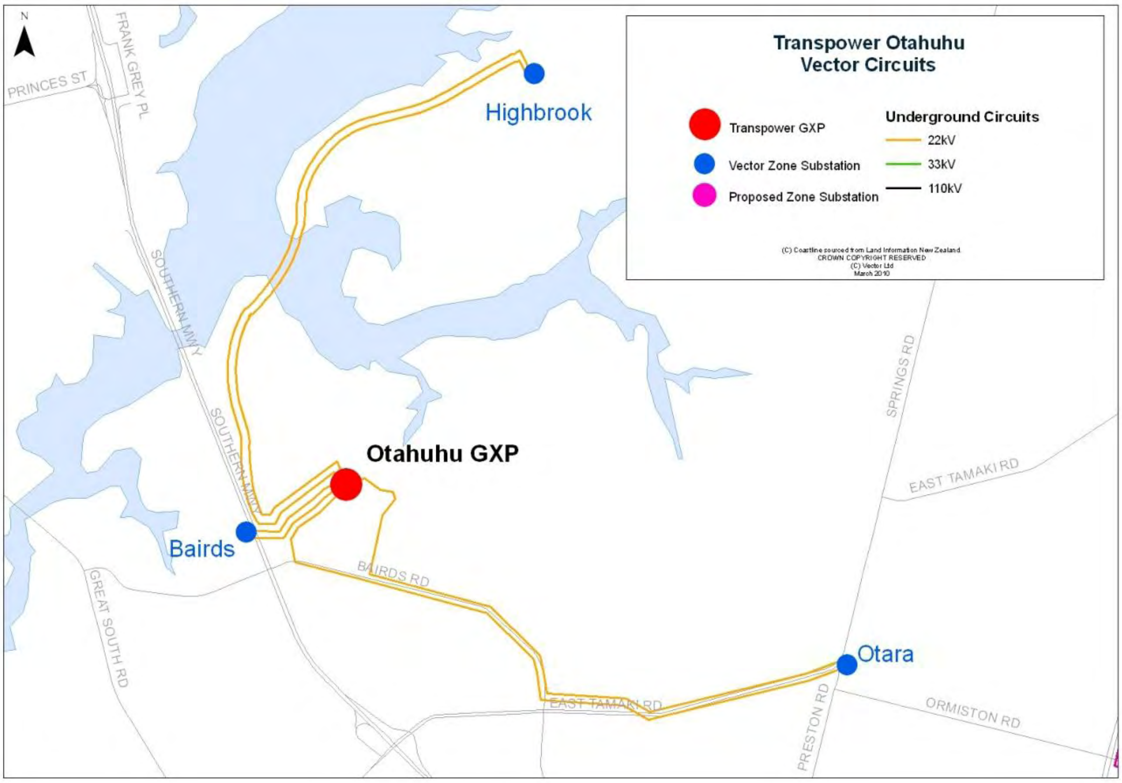


Figure 5-15 : Existing supply arrangement in the Otahuhu area

Projects – Next 12 Months

No network or non network expenditure required.

Projects – 2012 to 2015

No network or non network expenditure required.

Projects – Remainder of Planning Period (2016-2020)

No network or non network expenditure required.

5.8.11 Mangere GXP

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 and five zone substations are supplied from this Mangere 33kV bus, viz., Auckland Airport, Hans, Mangere Central, Mangere East and Mangere West. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual			Predicted								
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Mangere 33KV	118	81.2	83.9	92.6	101.6	107.4	113.6	120.1	124.0	128.8	133.7	137.5	141.5

WINTER MVA		Actual			Predicted								
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Mangere 33KV	118	94.9	103.5	111.1	118.1	122.0	126.0	130.0	133.8	138.4	143.0	146.7	150.4

Table 5-24 : Summer and winter load forecasts at Mangere 33kV sub-transmission network

The 2009 winter peak demand was 95MVA. This load is projected to increase to 147MVA towards the end of the planning period. The large increase is mainly due to the anticipated development of the area surrounding Auckland Airport. Vector also supplies a major customer (Pacific Steel) directly from the 110kV bus. The 110kV bus at this GXP is connected to Otahuhu and Roskill GXPs via overhead lines. The winter peak load will exceed the transformers' N-1 capacity in 2012.

Transpower will investigate removing the protection and equipment limits on the supply transformers. This will raise the N-1 limit to 138/143MVA (summer/winter). The capacity required at saturation for this GXP is 214MVA.

The following geo-schematic diagram shows the existing supply arrangement in the Mangere area.

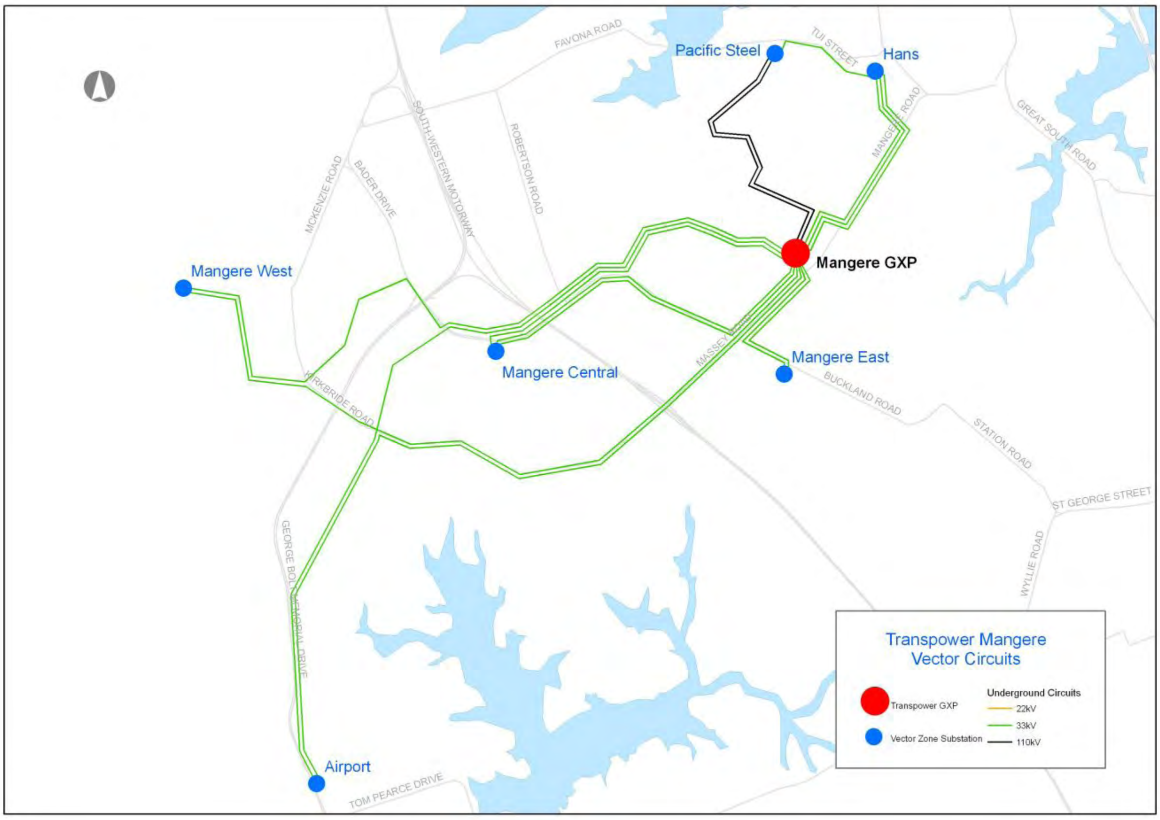


Figure 5-16 : Existing supply arrangement in the Mangere area

Projects – Next 12 Months

No network or non network expenditure required.

Projects – 2012 to 2015

No network or non network expenditure required.

Projects – Remainder of Planning Period (2016 to 2020)

It is planned to install a third transformer at Hans zone substation.

5.8.12 Wiri Sub-transmission GXP

Background

There are two 110/33kV 50/100MVA transformers installed at this 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 is 107/107MVA and two zone substations are supplied from this Wiri 33kV bus, viz., Manukau and Wiri. The summer and winter load forecasts are listed below.

SUMMER MVA		Actual	Predicted										
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wiri 33kV	92	65.4	74.5	78.3	82.4	86.7	91.3	96.2	98.9	101.6	104.4	107.3	110.3

WINTER MVA		Actual	Predicted										
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wiri 33kV	101	70.7	85.3	89.1	92.3	95.9	99.6	101.4	103.7	105.9	108.2	110.6	113.0

Table 5-25 : Summer and winter load forecasts for Wiri 33kV sub-transmission network

The 2009 winter peak demand was 71MVA. The present load projection indicates that the demand on this GXP will exceed 107MVA by about 2018.

Transpower is considering the following options to increase capacity:

- A third circuit from Otahuhu to Wiri, either an overhead line or an underground cable – a third supply transformer would be installed at Wiri and the existing Wiri T1 replaced with a 120MVA unit;
- An increase in the capacity of the 110kV Otahuhu to Wiri circuits by replacing the existing conductor with conductor of a higher rating - the two existing transformers would be replaced with two 240MVA supply transformers; and
- Create a new 220kV GXP under the Huntly to Otahuhu A line east of Wiri, and supply Wiri from that point via 33kV cables. This option would include re-conductoring the Otahuhu-Wiri circuits and eventually replacing Wiri T1 with a 120MVA unit.

The following geo-schematic diagram shows the existing supply arrangement in the Wiri area.

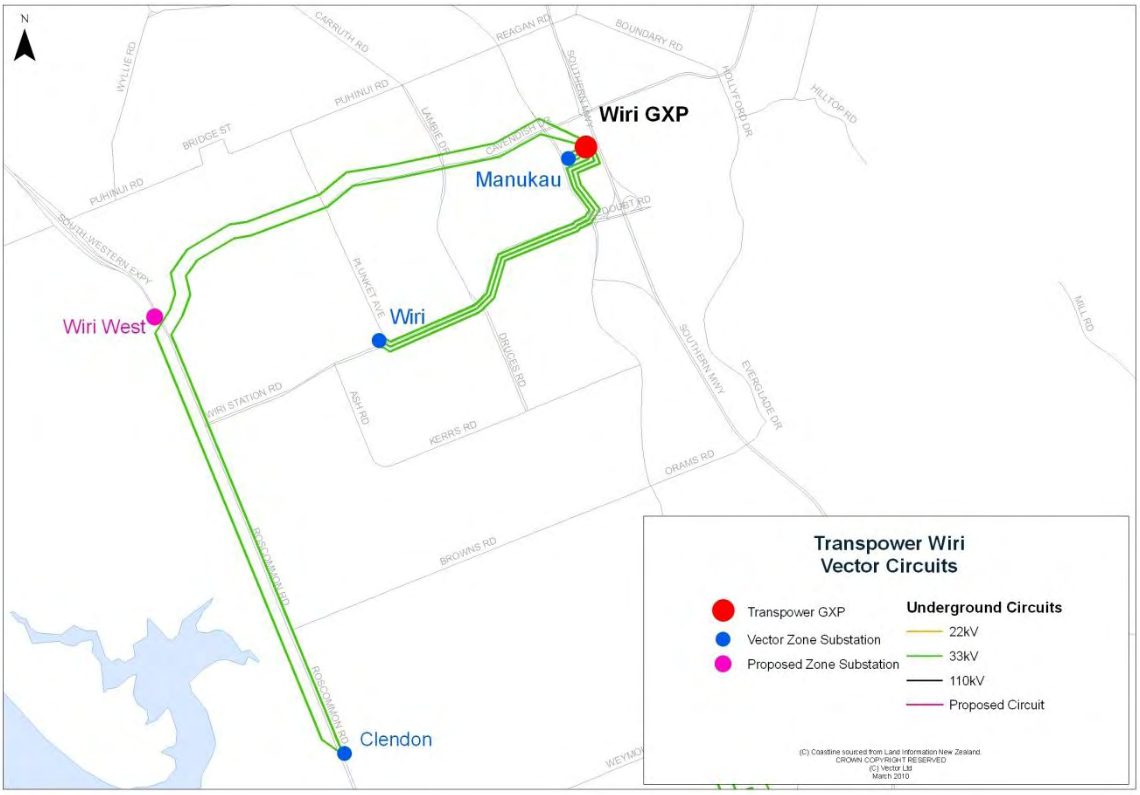


Figure 5-17 : Supply arrangement in the Wiri area

Projects – Next 12 Months

No network or non network expenditure required.

Projects – 2012 to 2015

No network or non network expenditure required.

Projects – Remainder of Planning Period (2016 to 2020)

Wiri West - install a new zone substation.

5.8.13 Takanini GXP

Background

Vector takes supply the Takanini 33kV bus via two 220/33kV 150MVA transformers. The N-1 capacity limit (winter/summer) of this GXP is 123/123MVA and six zone substations are supplied from this Takanini 33kV bus, viz., Takanini, Manurewa, Papakura, Clevedon, Maraetai and Waiheke.

The table below shows the summer and winter load forecasts at the GXP.

SUMMER MVA		Actual			Predicted								
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Takanini 33kV	123	66.3	65.2	70.0	75.1	80.6	86.6	93.1	94.9	96.7	98.5	100.4	102.4

WINTER MVA		Actual			Predicted								
Name	Capacity	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Takanini 33kV	123	115.9	105.3	105.9	106.4	107.0	107.6	109.7	111.5	113.3	115.2	117.1	119.1

Table 5-26 : Summer and winter load forecasts at the Takanini GXP

The winter load reduction at Takanini is due to load transfer to Wiri, made possible by the commissioning of Clendon substation in late 2009.

The two 220/33kV 150MVA transformers installed at this GXP have 123/123MVA (winter/summer) N-1 capacity limits. The 2009 peak demand was 115.9MVA. The projected demand at this GXP is expected to reach 119MVA towards the end of the planning period. The 220kV supply to this GXP is via a tee off from the two Glenbrook to Otahuhu 220kV circuits. No capacity or security issues are expected within the planning period.

The geo-schematic diagram in Figure 5-18 shows the existing supply arrangement in the Takanini area.

Projects – Next 12 Months

Following a request from Fonterra, it is planned to upgrade the 11kV supply to the Fonterra site at Takanini. This site is presently fed from Takanini TAKA 15 feeder via a SD3 unit installed within the site near the entrance to the property. The current capacity to this site is 4.7MVA. The upgrade will involve installation of a high capacity 7.5MVA feeder from Manurewa zone substation to Fonterra site and backstop this supply using existing TAKA 15 and PAPA 10 feeders.

Projects – 2012 to 2015

No network or non network expenditure required.

Projects – Remainder of Planning Period (2016 to 2020)

Install a new zone substation at south Takanini.

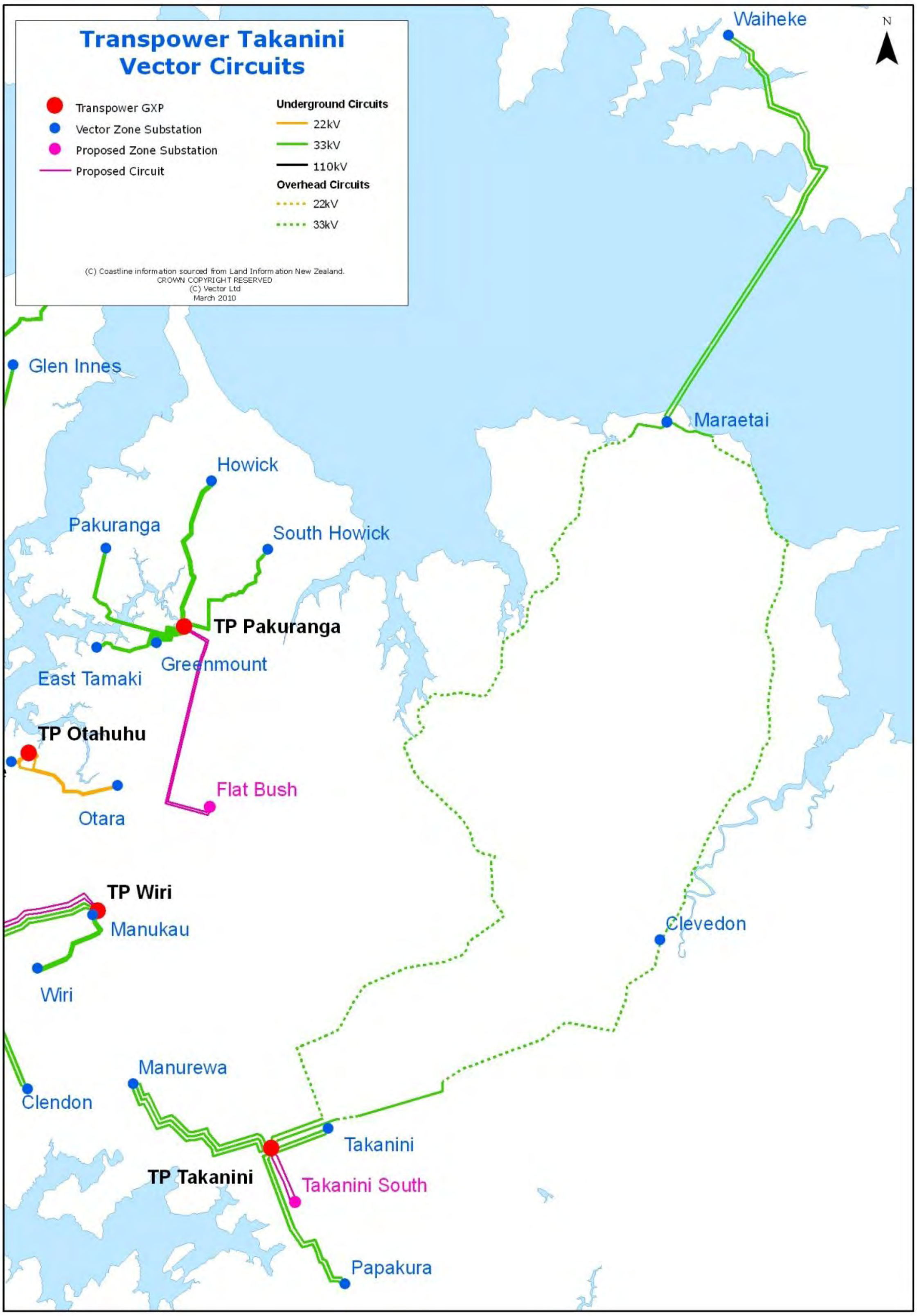


Figure 5-18 : Existing supply arrangement in the Takanini area

5.9 Asset Relocation

Vector's electricity network assets are required to be relocated to make way for work carried out by other infrastructure organisations or landowners (Requiring Authorities). Infrastructure projects could be initiated by other utilities (such as Transpower and Telecom) or roading authorities such as New Zealand Transport Authority (NZTA) and local councils. Vector is obliged by law to relocate its assets when requested. The process and funding of such relocation work is governed by the Electricity Act and Transit Act.

The timing of these projects is driven by the authority concerned and generally without the level of advance notice or detailed scope normally associated with growth projects. Information about projects more than one year in advance is generally not available for all but the large multi-year projects. In this respect 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 $2.5 million per annum.

Following is a list of known large infrastructure projects that require relocation of Vector electricity network assets:

- ONTRACK has initiated a project to upgrade the Auckland rail network by providing double-tracking and electrification. Relocation of existing 11kV and LV cables is required at various railway crossing sites to either provide sufficient clearance for the railway works or to relocate assets that are in the passage of the widened rail corridor;
- NZTA widening of SH1 at Warkworth. This affects a number of intersections and lines and cables are being relocated;
- NZTA are extending the Greenhithe motorway from the new Greenhithe Bridge to Westgate. Several intersections are affected and provision is being made for future 33kV and 11kV cabling as part of the works. This work is expected to continue over the next two to three years;
- NZTA is planning to widen the North-Western motorway from Waterview through to Westgate;
- NZTA plans to construct a tunnel between the Harbour Bridge motorway off ramp at Fanshawe Street and Victoria Park. Vector's existing 11kV and LV cables around Curran Road, Fanshawe Street/Beaumont Street intersection will need to be relocated. This is at the planning and design stage;
- NZTA plans to construct a tunnel between Waterview and Avondale. Existing 11kV and LV cables that impinge on the work area will need to be relocated. This project is at the planning stage;
- Auckland City Council has planned to upgrade and make improvements to CBD locations including Upper Khartoum Place, Elliott Street, Darby Street, Fort Street area and Lorne Street. This project is at the planning and design stage;
- Auckland City Council has initiated the project to upgrade and improve roads and public transport facilities around Eden Park. The project is underway and will be completed before Rugby World Cup in 2011;
- Watercare and Metrowater have initiated a project to upgrade the water mains around Mt Wellington Quarry. Most works are being carried out in conjunction with the Mt Wellington Quarry subdivision development;

- Relocation of water mains at Lunn Avenue, Norman Lesser Drive and Ngahue Drive will be carried out and completed in mid 2010;
- Watercare proposes to install a new water main from Redoubt North Reservoir in Manukau to Market Road in Epsom. The project is at the proposal stage;
- Manukau Harbour Crossing Alliance (comprising NZTA, Fletcher Construction, Beca Infrastructure and Higgins Contractors) is carrying out a project to improve SH20 across the Manukau Harbour between Mangere and Onehunga. This project is scheduled to for completion in 2011;
- Transpower has initiated a 400kV transmission line construction between Whakamaru to Browns Hill Road as part of North Island Grid Upgrade (NIGUP) project and Vector is relocating its assets to make way for this line;
- NZTA has initiated the Manukau extension project to link SH1 and SH20. To facilitate this project Vector has to relocate assets in:
    - Great South Road;
    - Wiri Station Road;
    - Lambie Drive;
    - Plunket Avenue;
    - Nesdale Avenue;
    - Roscommon Road; and
- Manukau City Council is planning to upgrade the Flat Bush School Road/Murphy Road intersection. This project is in the planning stage.

5.10 Protection, Automation, Communication and Control

Vector's distribution network is evolving and adapting to customers' needs while responding to the changes and challenges ahead – including an expectation that it will be necessary to integrate distributed energy resources, assure improved resilience and quality of supply, and be safe, economic and efficient. This will result in continuously increasing complexity of the network and will necessitate incremental deployment and integration of sensors, intelligent electronic devices (IED), and information and communication technologies.

In order to deal with challenges ahead, adoption and deployment of a standards based power system information infrastructure is vital. The following two figures show the two systems (power and information systems) utilities have to manage.

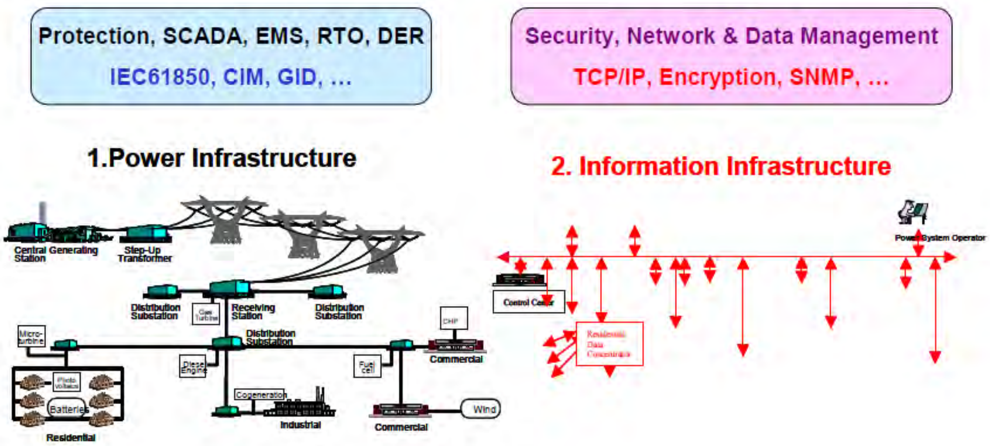


Figure 5-19 : Two infrastructures utilities manage

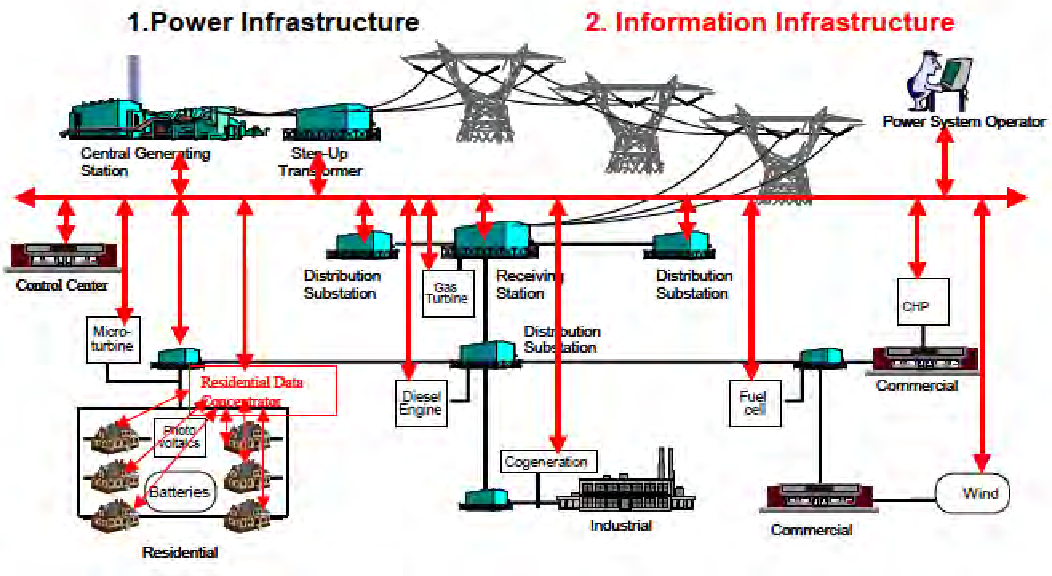


Figure 5-20 : Power system infrastructure with integrated information and communication systems

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.

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 5-21 shows the IEC TC57 reference architecture.

The reference architecture reflects the ultimate objectives for an information infrastructure that can meet all business's needs, including network configuration requirements, quality of service requirements, security requirements, and data management and exchange requirements. It will enable unification of:

- Abstract modelling;
- Security management;
- Network and system management;
- Data management and exchange; and
- Integration and interoperability.

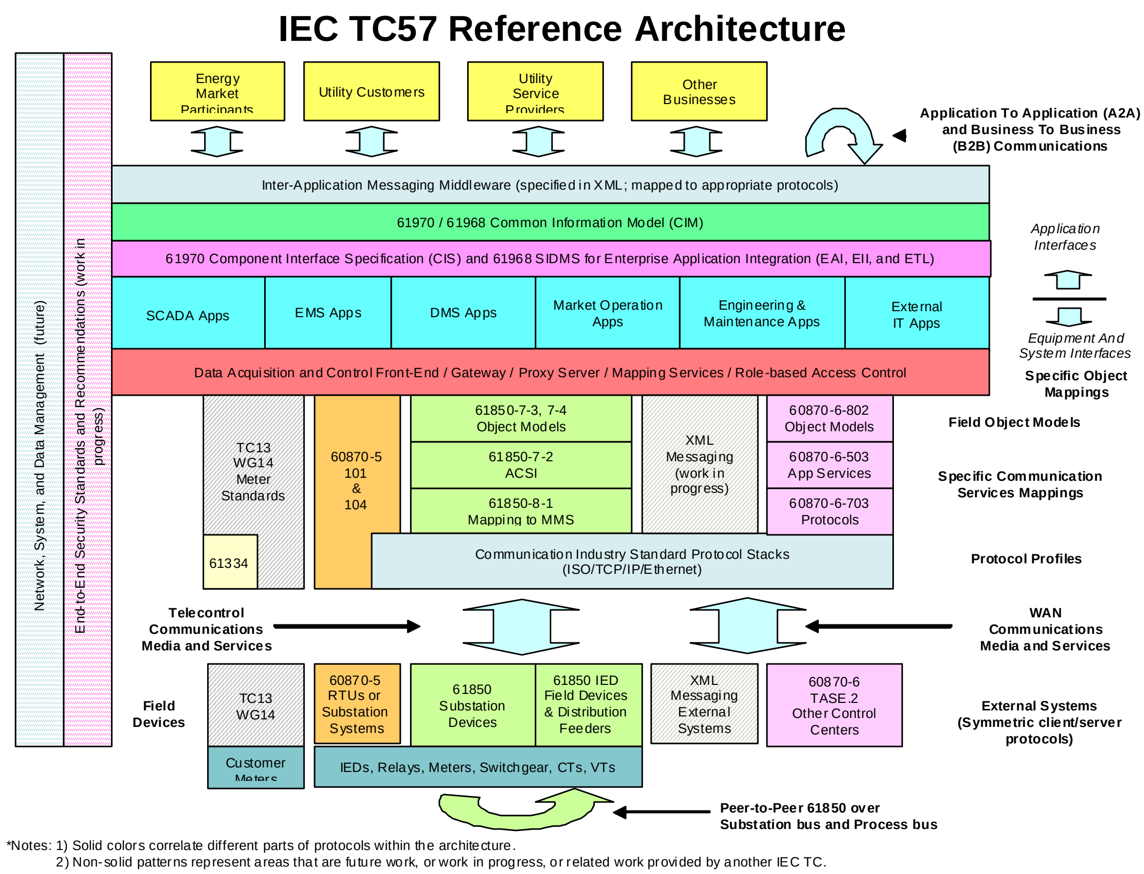


Figure 5-21 : IEC TC57 reference architecture

Standards

The following table and figure show a summary of the standards used in the power system information and control systems and how they interrelate.

Standard	Domain
IEC 61850 - Power Utility Automation	Network Automation
IEC 60870-6 / TASE.2 Inter-control centre communications	Control Center
IEC 61968	Application integration at electric utilities – System interfaces for distribution management
IEC 61970	Energy management system application program interface (EMS-API Common Information Model)
IEC 62351	Information security for power system control operations
ISO / IEC 27002	
NERC CIP 002-009	Cyber security standards for the bulk power system

Table 5-27 : Future network interoperability standards

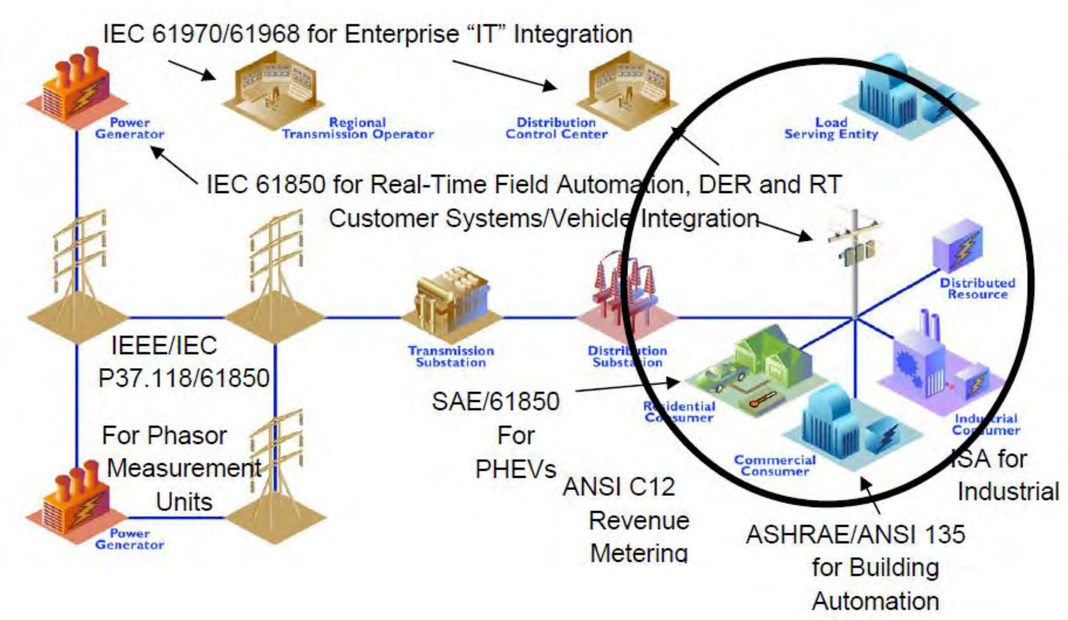


Figure 5-22 : Future network domains showing some relevant standards

5.10.1 Network Automation at Vector

5.10.1.1 Substation Automation

Substation automation describes the collection of auxiliary systems within a substation that enables the coordination of protection, automation, monitoring, metering and controls functions. Vector's substation automation system is based on resilient Ethernet local area network running IEC 61850 compliant IEDs. The following diagram shows Vector's substation automation system.

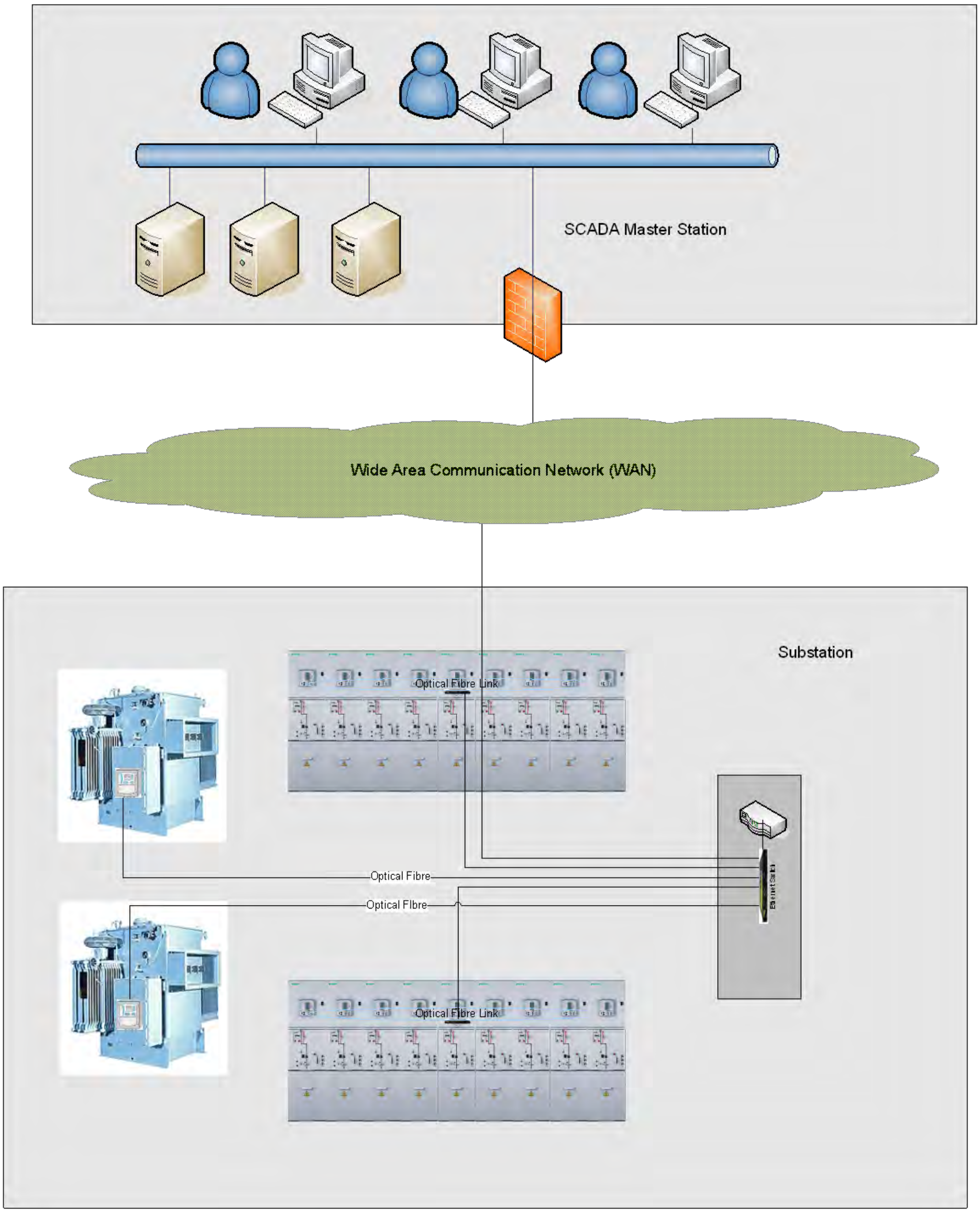


Figure 5-23 : Vector's typical substation automation system

5.10.1.2 Distribution Automation – MV/LV Substation

Vector has deployed over 300 poles using GPRS/3G IP centric third party communication network and DNP3 communication protocol.

5.10.1.3 Technical Application Integration

The integration of advanced technical analysis applications with other systems in distribution operations is complex.

The International Electrotechnical Commission (IEC) Common Information Model (CIM) is an abstract data model that is recommended to represent the major objects in an electric utility enterprise and facilitate the application integration.

IEC 61970/61968 standardises:

- A shared device information (data) model:
  - The CIM; and
- A shared set of services:
  - The Generic Interface Definition (GID).

The following diagram shows the distribution management system adopted by Vector.

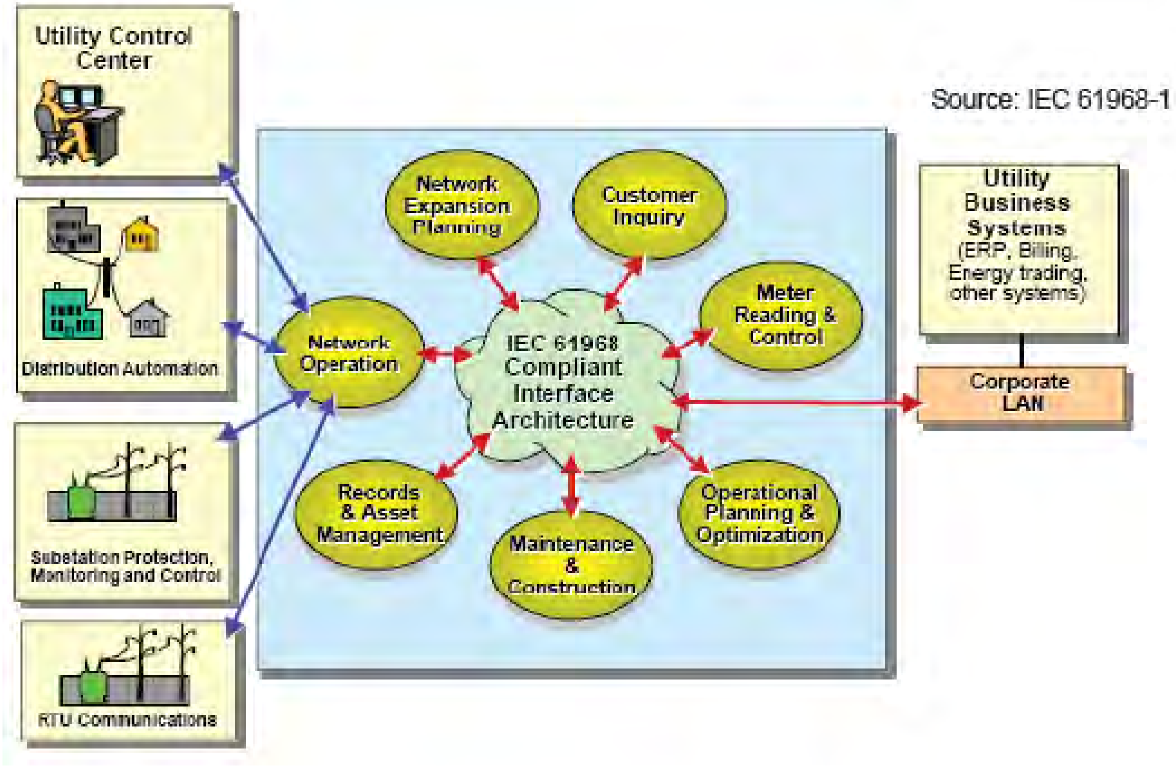


Figure 5-24 : Distribution management system with IEC 61968 compliant architecture

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.

The following diagram shows the application integration of the Vector control systems.

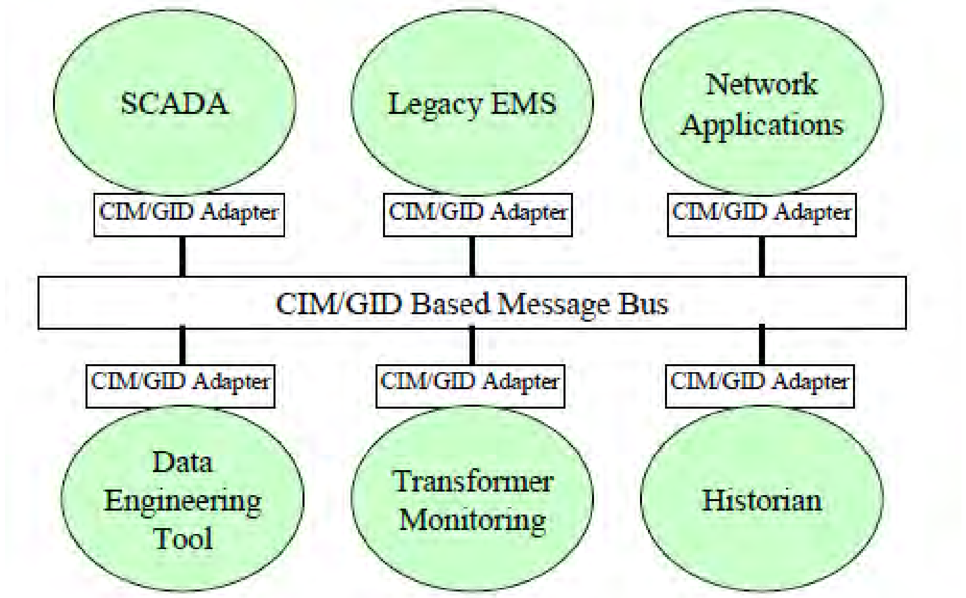


Figure 5-25 : Application integration scenario

An approach to facilitate incremental upgrading of the Vector's control centre application integration is to use integration solution as shown in the figure below.

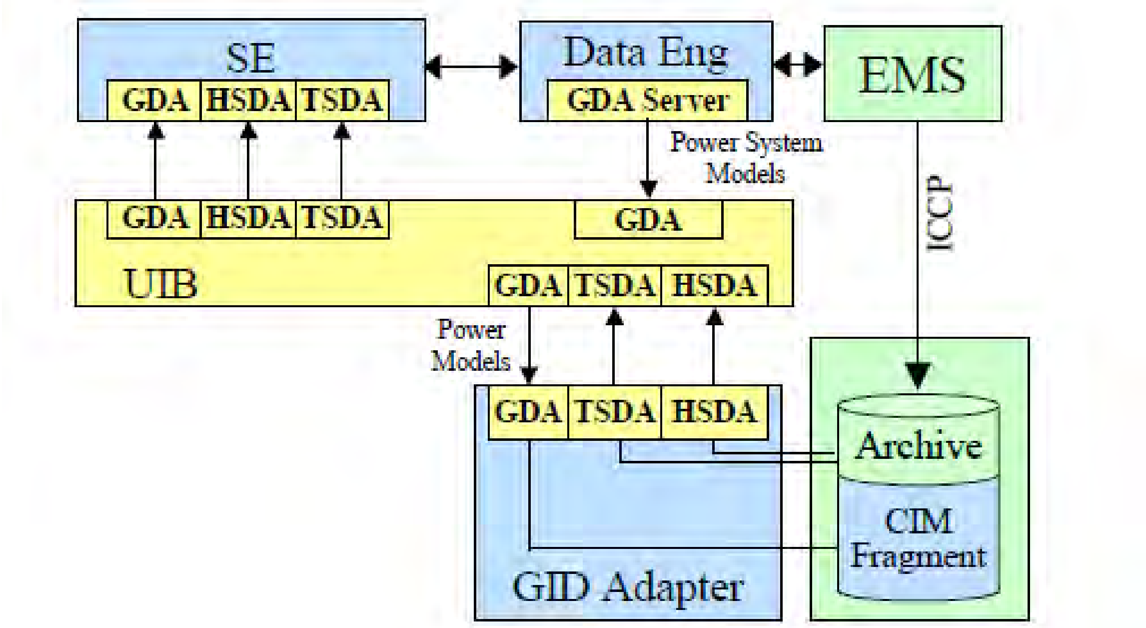


Figure 5-26 : Specific GID interfaces used for application integration

A feasibility study to use the above approach is currently underway.

5.10.1.4 Communication Systems

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 networks. 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 based (e.g. 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.

Vector's standard substation Local Area Network (LAN) and operational Wide Area Network is based on Ethernet and IP communication technology.

The Ethernet/IP based operational communication network carry's 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.

Teleprotection over IP, remote asset management, video surveillance are being planned.

The following diagram shows Vector's IP WAN.

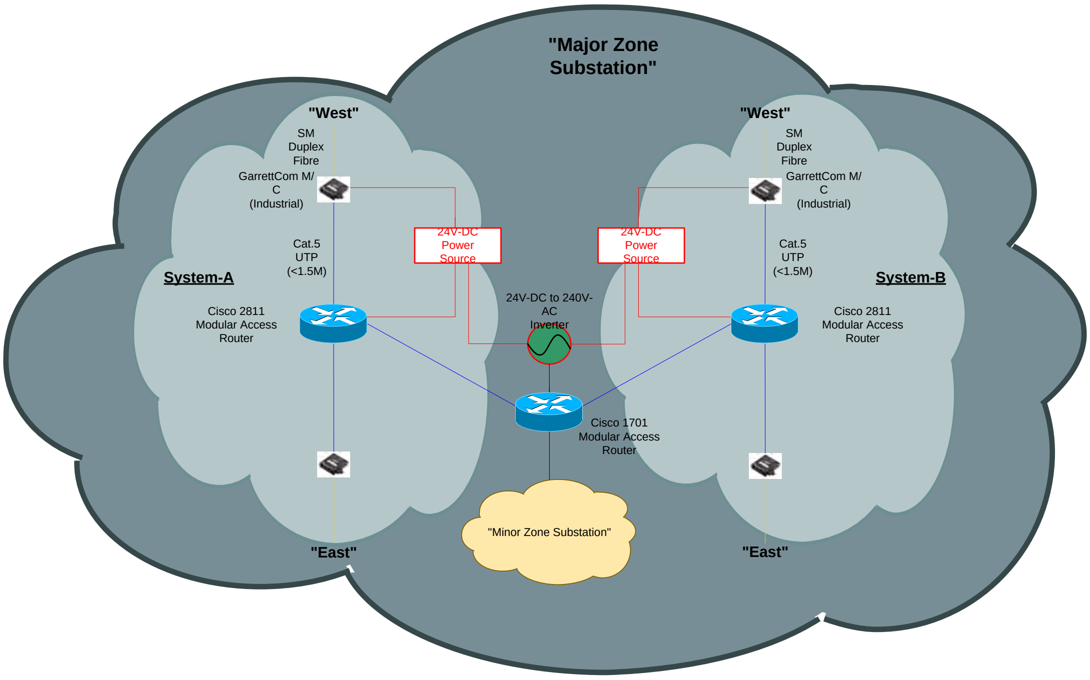


Figure 5-27 : Vector's IP WAN

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.

5.10.1.5 Cyber Security

Following a detailed audit in 2009 into the cyber-security standards of our 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 programs are also underway to ensure that the roles and responsibilities for the SCADA system – which lies across the business – are clearly allocated, and that adequate firewall protection and intrusion detection is provided for all parts of the system.

The following diagrams show the security requirements, threats, counter-measures, and management at Vector.

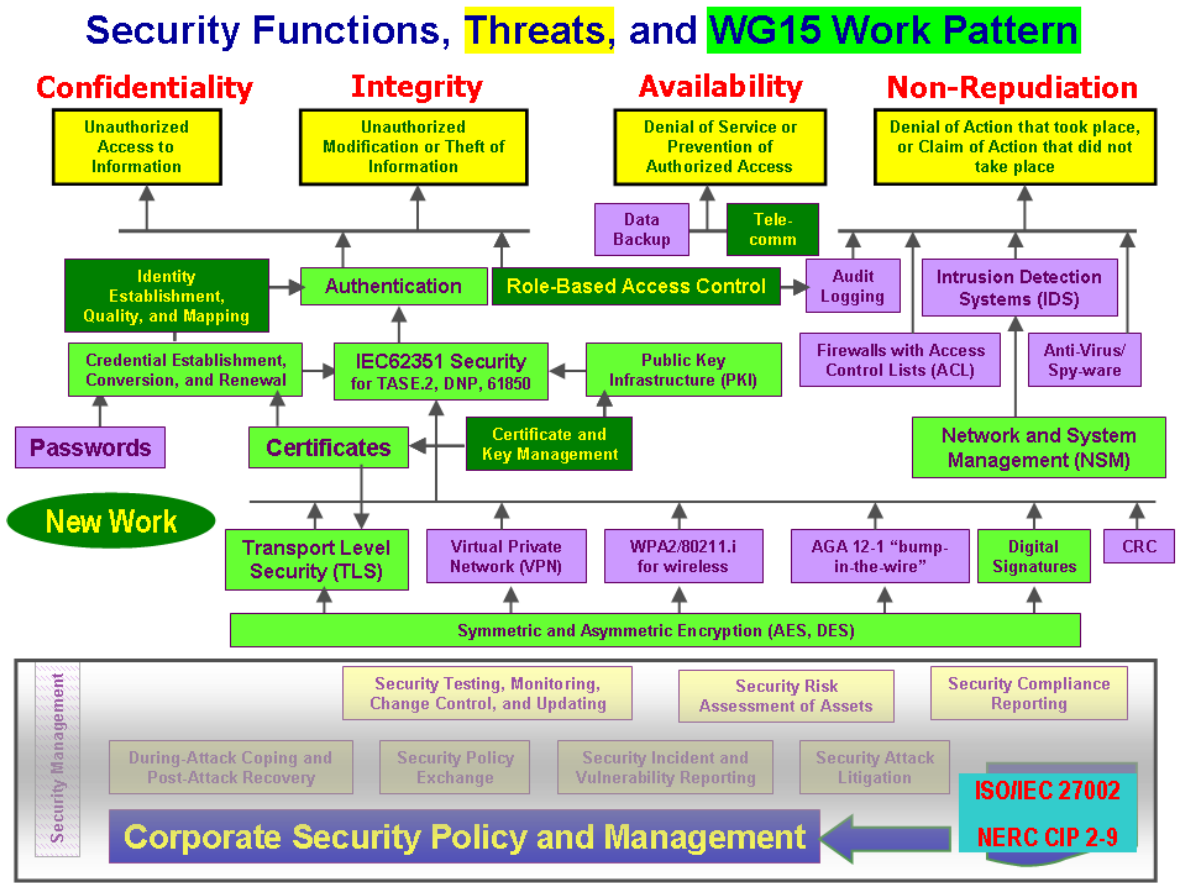


Figure 5-28 : Overall Security: Security requirements, threats, counter-measures, and management

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.

The IEC Technical Council (TC) 57 Power Systems Management and Associated Information Exchange is responsible for developing international standards for power system data communications protocols.

IEC TC57 has published 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.

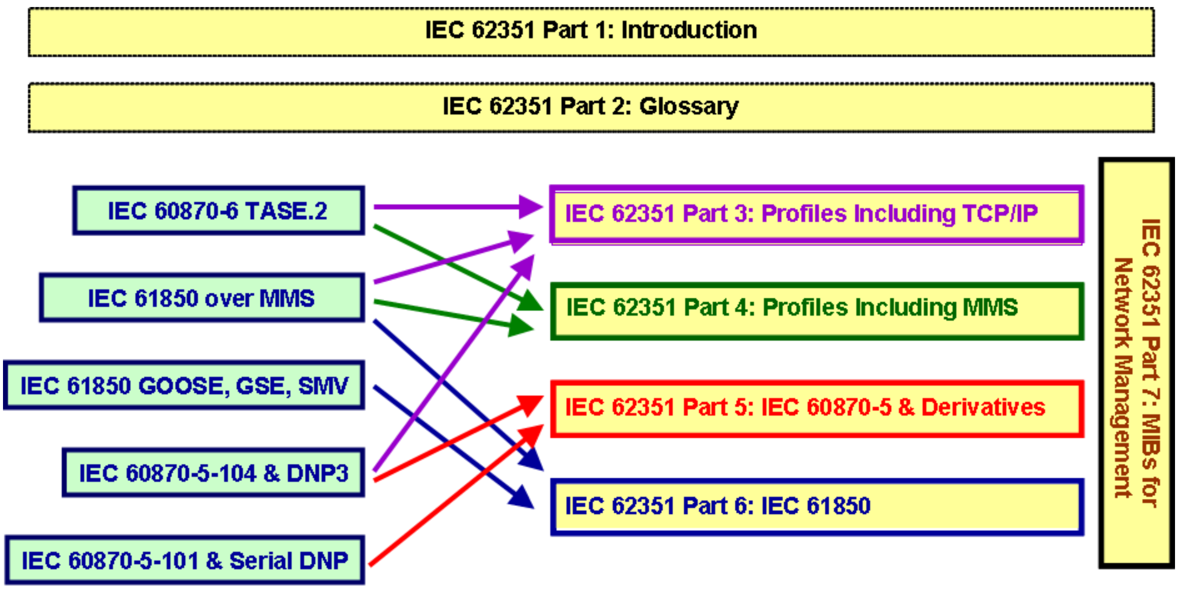


Figure 5-29 : Mapping of TC57 communication standards to IEC 62351 security standards

It is Vector's intention to incorporate IEC 612351 standard protocol security enhancements within the communication protocols Vector uses for its protection, automation and control systems when they become available in the products and are practicable to be implemented. Vector is committed to IEC specified communication protocol for its real time system and application interfaces.

5.10.1.6 Substation Information Management

The protection system modelling and settings is a vital part of the network modelling and simulations. Vector has implemented the protection setting management system StationWare from DIgSILENT that has interface to DIgSILENT network analysis and protection setting tool PowerFactory. Both products are planned to support IEC 61850 and CIM. The following table summarises Vector's protection and control development programme.

Domain	Project Description	Period	Benefits
Network Automation	MV/LV substation automation – pilot project	2010	Cost Efficiency Operational Excellence
Network Automation	MV/LV substation automation – rollout	2011 - 2015	Cost Efficiency & Operational Excellence
Network Automation	Centralised automatic load shift scheme based on CIM model - feasibility	2010	Cost Efficiency
Network Automation	Load Shedding Scheme based for identified substation – solutions for both conventional RTU based and IEC 61850 substation systems	2011 - 2015	Cost Efficiency
Control Centre	Complete Migration of Northern SCADA to Power TG application	2011	Cost Efficiency & Operational Excellence

Domain	Project Description	Period	Benefits
Communication Systems	Increase availability of third party cellular network for distribution automation	2010 - 2011	Operational Excellence
Protection System	Replacement / Refurbishment based on asset condition / system adequacy	2010 - 2015	Operational Excellence
Cyber Security	Various projects to address identified deficiency	2010 - 2015	Operational Excellence

Table 5-28 : PAC development plan

5.10.2 Network Protection – Design Standards

The main functions of a 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 end 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.

5.10.2.1 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 the table below.

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 5-29 : Maximum fault clearing time

Fault clearing time of the back-up protection shall not exceed the short-circuit thermal withstand capability of the primary equipment.

5.10.2.2 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 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.

5.10.2.3 Line Protection

The following table 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 - Overcurrent and Earth Fault (50 /51-50N/51N)
Underground Cable	11kV	Main - Overcurrent and Earth Fault (50 /51) Back-up - Overcurrent and Earth Fault (50 /51)

Table 5-30 : Line protection schemes

Dedicated optical fibres are used for all communication assisted protection schemes (e.g. longitudinal differential protection scheme).

5.10.2.4 Auto Reclosing

Auto-reclosing is applied to overhead network but not to the underground cable or combined underground cable and overhead lines.

5.10.2.5 Busbar Protection

The following table 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 - Overcurrent-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 - Overcurrent 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 - Overcurrent and Earth Fault (ANSI 50/51-50N/51N)
33, 22 and 11kV AIS	Main - Low Impedance differential protection (ANSI 87BB) Back-up - Overcurrent and Earth Fault (ANSI 50/51-50N/51N)

Table 5-31 : Busbar protection schemes

5.11 Power Quality

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 (PQ) monitoring is to identify disturbances that could adversely impact on customer's equipment with the objective of identifying solutions.

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.

5.12 Network Development Programme

The following tables summarise the project programme for development of the power network in the two regions. The table below 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	Description of Project	Implementation Date from Previous AMP	Comments
2010	Birkdale	Stanley Road 11kV feeder extension	2009	Project complete
2010	Bush Road	Schnapper Rock 11kV feeder reinforcement	2009	Project complete
2010	Te Atatu	Lincoln 11kV feeder (Woodford) reinforcement	2009	Project complete
2010	Waikaukau	33kV rearrangement	2009	Project complete
2011	Atkinson Road	Upgrade of zone substation	2015	Upgrade of existing substation due to load growth
2011	Chevalier	Reinforcement for Waterview tunnel temp supply	N/A	New project, customer driven
2011	Chevalier	Install second 33/11kV transformer	2015	Required due to tunnel construction
2011	Clendon	Reinforce Wiri South 11kV network	N/A	Project initiated due to growth and forecast load
2011	Customer B	Stage 1A upgrade of supply to customer B	N/A	New project, customer driven
2011	Flatbush	Purchase of land for new zone substation	N/A	Site is in the process of being identified
2011	Glenvar	Establish zone substation and reinforce 33kV network	2014	Relieves Torbay substation backstop shortfall
2011	Greenhithe	Establish zone substation and 33kV network extension	2011	Project underway, initiated due to load growth
2011	Greenmount	New 11kV feeder to Armoy Drive	N/A	Project initiated due to growth and forecast load
2011	Henderson Valley	Valley Road 11kV feeder reinforcement	N/A	New project, overloading in summer
2011	Hobson	Establish 22kV feeders to Tank Farm development	N/A	New project, customer driven
2011	Hobson	Supply to Victoria park roadway tunnel	N/A	New customer driven project
2011	Keeling Road	Reinforcement of Valley Road 11kV feeder	N/A	Required due to growth and forecast load
2011	Liverpool	Liverpool substation - replace 110/22kV transformers	N/A	Replacement of ageing transformers
2011	Mangere East	Upgrade Supply to Customer A	N/A	New project, customer driven
2011	Manurewa	Upgrade Supply to Customer C	N/A	New project to supply large industrial customer

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2011	Newmarket South	Purchase of land for new zone substation	N/A	Site is in the process of being identified
2011	Orewa	Orewa zone substation - Weranui 11kV feeder	N/A	Required due to growth and forecast load
2011	Otara	New 11kV feeder	N/A	Project initiated due to growth and forecast load
2011	Quay	Liverpool to Quay 110kV sub-transmission cables	N/A	New project to enhance security to Auckland CBD
2011	Quay	22kV feeders to Queens Wharf	N/A	New project, driven by customer requirements
2011	Ranui	Establish zone substation	2010	Project underway, initiated due to load growth
2011	Rosedale	Zone substation land purchase	N/A	In process of identifying a site
2011	Waimauku	Zone substation upgrade: install second transformer	2012	Defers Kaukapakapa substation
2011	Warkworth	33kV line reinforcement	N/A	New project, upgrade to existing line
2011	Westgate	Zone substation land purchase	N/A	Sites being identified
2011	Wiri	Extend existing 11kV feeder	N/A	Project initiated due to growth and forecast load
2011	Wiri West	Zone substation land purchase	N/A	Project initiated due to growth and forecast load
2012	Bairds	Reconfigure 11kV feeders one and two	N/A	Reconfiguration due to load growth
2012	Hillsborough	Hillsborough auto load shifting scheme	N/A	Project initiated due to growth and forecast load
2012	Hobsonville	Reinforcement of the Clark Road 11kV feeder	N/A	Reinforcement defers Hobsonville East substation
2012	Liverpool	Extend 22kV switchboard - feeders to Auckland CBD (stages one, two)	N/A	Project initiated due to growth and forecast load
2012	Liverpool	Stage One of 11kV supply to Medical School	N/A	New project, customer driven
2012	Mangere East	Rearrange 11kV feeders 13, 15 and 19	N/A	Project initiated due to growth and forecast load

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2012	Mangere West	Extend 11kV feeder two	N/A	Project initiated due to growth and forecast load
2012	Mt Albert	Auto load shifting scheme	N/A	Project initiated due to growth and forecast load
2012	Otara	Otara zone substation - 11kV feeder nine reinforcement	N/A	Required due to growth and forecast load
2012	Ponsonby	Load shedding & auto shifting scheme	N/A	Project initiated due to growth and forecast load
2012	Remuera	Reinforce 11kV feeder no 12 from Remuera	N/A	Project initiated due to growth and forecast load
2012	St Heliers	Load shedding & auto shifting scheme	N/A	New project, load forecast reviewed
2012	Takanini	11kV Mill Road feeder from Takanini zone substation	N/A	Project initiated due to growth and forecast load
2012	Wairau	Replace outdoor 33kV switchgear with indoor switchgear	N/A	Project driven by GXP upgrade to increase security
2012	Wairau	Reroute 110kV OH circuits as part of enabling works for GXP	N/A	New project, enabling work for Wairau GXP
2012	Waitakere	Establish zone substation	2012	Project initiated due to growth and forecast load
2012	Warkworth	New 11kV feeder to Warkworth South (use 33kV cable)	N/A	Defers establishment of Warkworth South substation
2013	Customer B	Stage 1B upgrade of supply to customer B	N/A	New project, customer driven
2013	Drive	11kV load shedding scheme	N/A	New project, load forecast reviewed
2013	Flatbush	11kV feeder reinforcement to Flatbush area	N/A	Project initiated due to growth and forecast load
2013	Hans	11kV feeder to reinforce Savill Drive	N/A	New project, load forecast reviewed
2013	Helensville	Kaukapakapa/South Head 11kV reinforcement	N/A	Installation of feeder defers Kaukapakapa substation
2013	Hillsborough	11kV feeder	N/A	New project, load forecast reviewed

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2013	Hobson	Development of the airspace above Hobson substation in CBD	N/A	Dependant on commercial viability and ACC approval
2013	Hobson	Installation of a 110kV switchboard as part of new GXP	N/A	Required to provide for growth and security
2013	Hobson	Extend the 22kV switchboard	2010	Deferred from 2010 to 2014
2013	Mangere Central	Installation of 11kV feeder to Massey Road	N/A	Project initiated due to growth and forecast load
2013	Manly	Arkles Bay 11kV feeder reinforcement	N/A	Overloading in summer
2013	Manurewa	11kV feeder in Christmas Road	N/A	Project initiated due to growth and forecast load
2013	Manurewa	11kV Feeder to Takanini	N/A	Project initiated due to growth and forecast load
2013	New Lynn	Totara Avenue 11kV feeder reinforcement	N/A	Overloading in summer
2013	Newton	Load shedding & auto shifting scheme	N/A	Project initiated due to growth and forecast load
2013	Penrose tunnel	Enhanced fire suppression for Transpower cables	N/A	Transpower NAaN project
2013	Quay	Ports of Auckland reinforcement	N/A	New project, customer driven
2013	Quay	22kV switchboard extension	2010	Deferred to 2013 due to optimised design
2013	Rockfield	11kV feeder reinforcement	2011	Project initiated due to growth and forecast load
2013	Rosebank	Rosebank North zone substation - land purchase	N/A	Required due to growth and forecast load
2013	Rosebank North	Rosebank North zone substation - establish	N/A	Required due to growth and forecast load
2013	Rosedale	Establish a zone substation in Rosedale	2013	No change in implementation date
2013	St Johns	33kV reinforcement	2017	Brought forward due to revised load forecast
2013	Waiwera	Zone substation land purchase	N/A	New project
2014	Balmoral	Reinforcement of 11kV network	2018	The works is driven by customer demand

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2014	Freemans Bay	Reinforcement 11kV network - Freemans Bay zone substation	2014	Load forecast reviewed
2014	Hobsonville East	Zone substation land purchase	N/A	New project
2014	Newmarket South	Establish a zone substation in Southern Newmarket	2012	Project will be required due to forecast load
2014	Orakei	Load shedding scheme	N/A	New project, load forecast reviewed
2014	Otara	11kV feeder to Chapel Road	N/A	Project initiated due to growth and forecast load
2014	Quay	Retire ageing 110/22kV transformers and replace	2012	Load and forecast allowed deferment to 2014
2014	Red Beach	Second 33/11kV transformer	N/A	To provide shortfall in 11kV backstopping
2014	Rosebank	11kV feeder reinforcement	2012	Load forecast reviewed
2014	Takanini	11kV feeder to Porchester Road	N/A	Project initiated due to growth and forecast load
2014	Takanini South	Procurement of land for a zone substation	N/A	To establish a zone substation - due to load forecast
2014	Warkworth	Reinforcement of Whangateau 11kV feeder Warkworth zone SS	N/A	Required due to growth and forecast load
2014	Wellsford	Whangateau 11kV feeder reinforcement	N/A	Overloading in summer
2015	AIAL	Customer B upgrade Stage 2A	N/A	The works is driven by customer demand
2015	Avondale	11kV reinforcement for Waterview tunnel south portal	2012	Brought forward due to revised customer requirement
2015	Avondale	Avondale zone substation - establish 33kV switchboard	N/A	Required due to growth and forecast load
2015	Bairds	11kV reinforcement using ex 22kV cables	N/A	New project, load forecast reviewed
2015	Ellerslie	Establish zone substation	2011	Deferred to 2015 due to revised load forecast
2015	Hobson	Install a third 110/22kV transformer	2016	Project initiated due to growth and forecast load

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2015	Hobsonville East	Establish zone substation	2016	Project initiated due to growth and forecast load
2015	Liverpool	Medical School 11kV reinforcement stage two	N/A	Project due to growth and forecast load
2015	Liverpool	Telecom Mayoral Drive 22kV feeders	2009	Project initiated by and pending customer
2015	Mangere Central	Establish Emergency Backstop to Customer B	N/A	New project, load forecast reviewed
2015	Manurewa	Manurewa Super Clinic upgrade	N/A	New project, customer driven
2015	Maraetai	Reinforce 11kV feeder nine	N/A	New project, load forecast reviewed
2015	Newmarket	11kV reinforcement to Newmarket North	2012	Deferred to 2015 due to revised load forecast
2015	Newmarket	11kV supply to ex Lion Breweries site	N/A	Project initiated by and pending customer
2015	Orewa	Install a third 33kV circuit to Orewa zone substation	2015	Project initiated due to growth and forecast load
2015	Orewa	Savoy 11kV feeder reinforcement (spare two extension)	N/A	New project, load forecast reviewed
2015	Orewa	Centreway 11kV feeder reinforcement	N/A	New project, load forecast reviewed
2015	Sandringham	Supply to south portal of Waterview roadway tunnel	N/A	New project, customer driven
2015	Sandspit	Establish zone substation	2015	Project initiated due to growth and forecast load
2015	St Johns	11kV reinforcement to Auckland University Tamaki campus	2012	Deferred to 2015 due to revised load forecast
2015	Te Atatu	Waterview tunnel supply, north portal	N/A	New project, customer driven
2015	Te Papapa	11kV reinforcement	2011	Deferred to 2015 due to revised load forecast
2015	Waiheke	11kV voltage regulator	N/A	New project, load forecast reviewed
2015	Westgate	Establish a new zone substation at Westgate	2013	Deferred to 2014 due to revised

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
				load forecast
2016	East Tamaki	11kV feeder to Greenmount	N/A	New project, load forecast reviewed
2016	Flatbush	Establish a zone substation in Flatbush	2013	Deferred due to revised load forecast
2016	Greenmount	Reinforce 11kV to Crooks Road	N/A	New project, load forecast reviewed
2016	Greenmount	Reinforce 11kV to Lady Ruby Drive	N/A	New project, load forecast reviewed
2016	Greenmount	Install Auto Close device on 11kV bus	N/A	New project, load forecast reviewed
2016	Helensville	Establish new Rodney GXP for future power plant	N/A	Project is dependant on development of power plant
2016	Highbury	Install second 33/11kV transformer	2014	Required to provide backstop shortfall
2016	Hillsborough	Install second 33kV cable and 33/11kV transformer	2014	Deferred due to revised load forecast
2016	Kaukapakapa	Establish zone substation	2013	Deferred by 11kV reinforcement
2016	Lincoln	Zone substation land purchase	N/A	New project
2016	Liverpool	Replace the no three 110/22kV transformer	N/A	Replace ageing transformer
2016	Manly	Reinforce 33kV cable Red Beach-Manly	2014	Deferred to establishment of Red Beach substation
2016	Manukau	11kV feeder to Cavendish Drive	N/A	Project initiated due to growth and forecast load
2016	Manukau	11kV feeder to Te Irirangi Drive	N/A	Project initiated due to growth and forecast load
2016	Orewa/Manly	33kV submarine cable upgrade	N/A	Reviewed load growth
2016	Riverhead	33kV upgrade - circuit 22A (30m cable)	2010	Reviewed load growth
2016	Spur Rd	Wade River 11kV feeder reinforcement	N/A	Overloading in summer
2016	Sylvia Park	Sylvia Park 11kV feeders to offload CARB 10 and 18	N/A	Required due to growth and forecast load
2016	Wainui	Zone substation land purchase	N/A	New project
2016	Wairau	Establish 220kV GXP	N/A	New project

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
2016	Waiwera	Establish zone substation	2017	Required due to growth and forecast load
2017	Chevalier	11kV feeder	N/A	New project, to defer Mt Albert sub-transmission reinforcement
2017	Greenmount	11kV Lambie Drive Feeder	N/A	New project, load forecast reviewed
2017	Mangere Central	11kV reinforcement	N/A	New project, load forecast reviewed
2017	Te Atatu	Upgrade 33/11kV transformers	2018	No change to implementation date
2017	Warkworth South	Establish zone substation	2014	Deferred to 2107 operating 33kV feeder at 11kV
2017	Wellsford	Te Hana 11kV feeder reinforcement	N/A	New project, overloading in summer
2017	Wiri West	Establish zone substation	2017	Deferred due to revised load forecast
2018	Coatesville	Install second 33/11kV transformer	N/A	Required due to growth and forecast load
2018	Glen Innes	11kV reinforcement to off-load feeders six and thirteen	N/A	New project due to revised load forecast
2018	Kingsland	11kV reinforcement	2013	Deferred due to revised load forecast
2018	Kumeu	Zone substation land purchase	N/A	New project
2018	Newton	11kV reinforcement to offload Newton feeders 9, 10 & 22	N/A	Required due to growth and forecast load
2018	Oratia	11kV feeder to Piha from Oratia zone substation	N/A	New project
2018	Rockfield	11kV feeders to off-load McNab feeders 16 and 29	N/A	New project due to revised load forecast
2018	Takanini South	Establish zone substation	N/A	New project, load forecast reviewed
2018	Wainui	Establish zone substation	2018	Deferred due to revised load forecast
2018	Westfield	11kV reinforcement	2017	Deferred due to revised load

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
				forecast
2018	Woodford	Second 33/11kV transformer + 33kV reinforcement	N/A	Required due to growth and forecast load
2019	Albany	Establish zone substation	2018	Deferred due to revised load forecast
2019	Kumeu	Establish zone substation	2019	No change in implementation date
2019	Mt Albert	Sub-transmission reinforcement	N/A	Required due to growth and forecast load
2019	Tomarata	Establish zone substation	2016	Deferred due to revised load forecast
2019	White Swan	11kV reinforcement	N/A	Required due to growth and forecast load
2020	Keeling Road	Install second 33/11kV transformer and reinforce 33kV network	N/A	Required due to growth and forecast load
2020	Milford	Reinforce 33kV supply	N/A	New project, inadequate 11kV backstopping
2020	Mt Wellington	Load shedding scheme	N/A	Required due to growth and forecast load
2020	Northcote	Reinforce 33kV supply to Northcote zone substation	2014	Deferred due to revised load forecast
2020	Orakei	11kV reinforcement	2014	Deferred due to revised load forecast
2020	Warkworth	Third 33kV overhead line	2016	Deferred by reinforcing 33kV lines
2021	Hobson West	Establish zone substation	2018	Deferred due to revised load forecast
2021	Quay	Install a third 110/22kV Transformer	2016	This project deferred by Hobson transformer
Deferred	Avondale North	Establish zone substation	2015	Deferred, plan change due to Waterview tunnel
Deferred	Ellerslie	Install second 33kV cable and 33/11kV transformer	2014	Deferred, load forecast reviewed

Implementation Date	Substation	Description of Project	Implementation Date from Previous AMP	Comments
Deferred	Glen Innes	upgrade Glen Innes sub-transmission & transformer to 33kV	2014	Deferred, pending assets condition assessment
Deferred	James Street	Spinella feeder	2011	Updated connectivity model
Deferred	Onehunga	Upgrade Onehunga sub to 33kV	2015	Deferred, pending assets condition assessment
Deferred	Tamaki, proposed	Establish Tamaki substation	2017	Deferred, load forecast reviewed
Deferred	Westfield	Upgrade Westfield substation to 33kV	2013	Deferred, pending assets condition assessment
On-going	Hobson, Liverpool, Quay, Victoria	Auckland CBD 11kV to 22kV load transfer	N/A	
On-going	Hobson, Liverpool, Quay, Victoria	Auckland CBD 22kV switchboard extensions	N/A	
On-going	Southern	Future proofing ducts - Southern	N/A	
On-going	Southern	Minor feeder reinforcements - customer initiated - Auckland	N/A	As required pending customer demand
On-going	Southern	Substation load metering - Southern	N/A	
Replaced	Balmain	Transformer upgrade	2012	Replaced by Highbury second transformer project
Replaced	Birkdale	Beachaven feeder	2013	Updated connectivity model
Replaced	James Street	Elliot Street feeder	2013	Updated connectivity model
Replaced	Simpson Road	Second transformer	2013	Off-loaded to Ranui substation
Replaced	Titirangi	New zone substation	2011	Replaced by Atkinson Road project

Table 5-32 : Project programme for network development

Project expenditure and timing of the major projects planned by Vector for the planning period is shown in the table below, broken down into the following cost bands:

- A $0.5 million to $1 million;
- B $1 million to $2 million;
- C $2 million to $3 million;
- D $3 million to $4 million;
- E $4 million to $5 million; and
- F Greater than $5 million.

(Given that these cost estimates were based on a desktop study only, the accuracy levels are anticipated to be in the +30%/-10% range and putting point estimates on projects is therefore not considered appropriate. In addition, this information is commercially sensitive).

The estimated timing of the projects is by the coverage of the shaded cells.

Implementation Date	Substation or Area	Project Description	FY 11	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20
2011	Mangere East	Customer A - supply upgrade	C			C						
2011	Greenmount	New 11kV feeder to Armoy Drive	B									
2011	Manurewa	Upgrade Supply to Customer C	C									
2011	Quay	Liverpool to Quay 110kV sub-transmission cables										
2011	Wiri West	Procure land for establishment of zone substation	B									
2011	Ranui	Ranui zone substation - establish										
2011	Greenhithe	Establish zone substation and 33kV network extension										
2011	Atkinson	Upgrade of zone substation										
2011	Flatbush	Purchase of land for new zone substation	C									
2011	Newmarket South	Purchase of land for new zone substation	C									
2011	Quay	22kV feeders to Queens Wharf from Quay	B									
2011	Warkworth	Warkworth 33kV line reinforcement	A									
2011	Waimauku	Zone substation upgrade: second transformer	F									
2011	Glenvar	Establish zone substation and reinforce 33kV network	F									
2011	Chevalier	Reinforcement for Waterview tunnel temp supply	D									
2011	Remuera	Reinforce 11kV feeder no 12 from Remuera	A									
2011	Manurewa	Upgrade Supply to Customer C										

Implementation Date	Substation or Area	Project Description	FY 11	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20
2011	Keeling Road	Reinforcement Valley Road 11kV feeder from Keeling SS	A									
2011	Quay	Liverpool to Quay 110kV sub-transmission cables										
2011	Liverpool	Liverpool substation - replace 110/22kV transformers										
2011	Orewa	Orewa zone substation - Weranui 11kV feeder	A									
2011	Avondale	11kV reinforcement for Waterview tunnel south portal	B									
2011	Chevalier	Install second 33/11kV transformer	B									
2011	Hobson	Establish 22kV feeders to Tank Farm development	F									
2011	Hobson	Supply to Victoria Park roadway tunnel	B									
2012	Customer B	Stage 1A upgrade of supply to customer B		F								
2012	Liverpool	Extend 22kV switchboard feeders to Auckland CBD (stages one and two)		B								
2012	Liverpool	Stage one of 11kV supply to Medical School		A								
2012	Wairau	Reroute 110kV OH circuits as part of enabling works for GXP		B								
2012	Waitakere	Establish a zone substation		F								
2012	Hobsonville	Reinforcement of the Clark Road 11kV feeder		B								
2012	Otara	Otara zone substation - 11kV feeder nine reinforcement		A								
2012	Warkworth	New 11kV feeder to Warkworth South (use 33kV cable)		C								
2012	Quay	Ports of Auckland supply reinforcement		C								
2013	Customer B	Customer B - Stage 1B upgrade		F				F				
2013	Flatbush	11kV feeder reinforcement to Flatbush area			A							
2013	Mangere Central	Installation of 11kV feeder to Massey Road			A							
2013	Quay	Extend 22kV switchboard for new feeders to Auckland			B							
2013	Highbury	Highbury zone substation - Install second 33/11kV transformer			B							
2013	Rosedale	Establish a zone substation in Rosedale			F							
2013	Manurewa	11kV feeder to Christmas Road			A							
2013	Hobson	Development of the airspace above Hobson substation in CBD			F							
2013	Rosebank	Rosebank North zone substation - land purchase			A							
2013	Takanini	11kV Mill road feeder from Takanini zone substation			A							
2013	Penrose Tunnel	Enhanced fire suppression for Transpower cables			F							
2013	Hobson	Installation of a 110kV switchboard as part of new GXP			F							

Implementation Date	Substation or Area	Project Description	FY 11	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20
2013	Hobson	Extend the 22kV switchboard			D							
2013	Rockfield	Rockfield zone substation - 11kV reinforcement			B							
2013	St Johns	St Johns substation - 33kV reinforcement			E							
2013	Takanini	Procurement of land for a zone substation				E						
2014	Otara	Installation of 11kV feeder to Chapel Road				A						
2014	Takanini	11kV feeder to Porchester Road				A						
2014	Balmoral	Reinforcement 11kV network from Balmoral zone substation				A						
2014	Freemans Bay	Reinforcement 11kV network from Freemans Bay zone SS				A						
2014	Newmarket South	Establish a zone substation in Southern Newmarket				F						
2014	Quay	Retire ageing 110/22kV transformers and replace				E						
2014	Red Beach	Install second 33/11kV transformer				B						
2014	Warkworth	Reinforcement of Whangateau 11kV feeder from Warkworth SS				B						
2015	Sandringham	Supply to south portal of Waterview roadway tunnel					A					
2015	Manukau	Upgrade 11kV supply to Super Clinic					A					
2015	Sandspit	Establish a new zone substation in Sandspit					F					
2015	Westgate	Establish a new zone substation at Westgate					F					
2015	Orewa	Install a third 33kV circuit to Orewa zone substation					F					
2015	Avondale	Avondale area 11kV reinforcement					C					
2015	Ellerslie	Establish a zone substation in Ellerslie					F					
2015	Newmarket	Reinforce 11kV north Newmarket from Newmarket zone SS					A					
2015	St Johns	11kV reinforcement to Auckland University Tamaki campus					C					
2015	Te Atatu	Waterview tunnel - establish north portal substation and 33kV cct					F					
2015	Te Papapa	Te Papapa zone substation - 11kV reinforcement					B					
2015	Orewa	Reinforcement of Centreway 11kV feeder					A					
2015	AIAL	Customer B - Stage 2A upgrade					F					
2015	Rosebank	Rosebank North zone substation - establish					D					
2015	Avondale	Avondale zone substation - establish 33kV switchboard					A					
2015	Hobsonville East	Establish a zone substation in Hobsonville East					F					
2015	Hobson	Install a 3rd 110/22kV transformer					B					
2015	Liverpool	Medical School supply stage 2					B					

Implementation Date	Substation or Area	Project Description	FY 11	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20
2015	Liverpool	22kV feeder to Telecom (Mayoral Drive)					A					
2015	Newmarket	11kV feeder to ex-Lion Breweries site					B					
2015	Maraetai	Maraetai zone substation - reinforce 11kV feeder nine					B					
2016	Manukau	11kV feeder to Cavendish Drive						A				
2016	Manukau	11kV feeder to Te Irirangi Drive						A				
2016	Manly	Manly zone substation - install third 33kV cable						F				
2016	Liverpool	Replace the no three 110/22kV transformer						C				
2016	Lincoln	Land purchase for future Lincoln zone substation						A				
2016	Kaukapakapa	Kaukapakapa zone substation - establish						F				
2016	Waiwera	Establish a zone substation in Waiwera						C				
2016	Hillsborough	Install a second 33kV cable and 33/11kV transformer						C				
2016	Sylvia Park	11kV feeder to reinforce Carbine feeders 10 & 18						C				
2016	Flatbush	Establish a zone substation in Flatbush						F				
2017	Wiri West	Establish a zone substation in West Wiri							F			
2017	Warkworth	Establish a zone substation in Warkworth South							E			
2017	Takanini South	Establish zone substation							F			
2017	Rockfield	11kV feeders to off-load McNab feeders 16 and 29							B			
2017	Te Atatu	Upgrade two 33/11kV transformers							C			
2018	Glen Innes	11kV reinforcement to off-load feeders 6 and 13								A		
2018	Coatesville	Second 33/11kV transformer for Coatesville zone substation								A		
2018	Kumeu	Kumeu zone substation - establish								F		
2018	Oratia	11kV feeder to Piha from Oratia zone substation								B		
2018	Wainui	Establish a zone substation in Wainui								F		
2018	Woodford	Second 33/11kV transformer and 33kV network reinforcement								F		
2018	Kingsland	Kingsland zone substation - 11kV reinforcement								B		
2018	Newton	Reinforce 11kV feeders 9, 10 and 22 from Newton zone SS								B		
2018	Westfield	Westfield zone substation - 11kV reinforcement								B		
2018	Takanini	Establishment of a zone substation in Takanini South								F		
2019	Albany	Establish a zone substation in Albany									E	
2019	Mt Albert	Mt Albert zone substation - 33kV reinforcement									C	
2019	White Swan	White Swan zone substation - 11kV reinforcement									B	
2019	Tomarata	Tomarata zone substation - establish									E	
2020	Keeling Road	Install second 33/11kV transformer and reinforce 33kV										B

Implementation Date	Substation or Area	Project Description	FY 11	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20
		network										
2020	Warkworth	Establish third 33kV line to Warkworth										D
2020	Northcote	Reinforce 33kV supply to Northcote zone substation										B
2020	Orakei	Orakei zone substation - 11kV reinforcement										A
2020	Milford	Reinforce 33kV supply										B
2021	Hobson West	Establish zone substation										

Table 5-33 : Timing and estimated cost of major growth projects until 2020

5.12.1 Network Development Expenditure Forecast

In Table 5-34 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.

Financial Year Ending	Mar 11	Mar 12	Mar 13	Mar 14	Mar 15	Mar 16	Mar 17	Mar 18	Mar 19	Mar 20
Zone substation	$13.7m	$15.9m	$14.0m	$16.7m	$14.8m	$14.1m	$18.5m	$24.6m	$19.7m	$22.8m
CBD reinforcements	$11.0m	$4.3m	$15.3m	$18.7m	$5.3m	$3.3m	$1.0m	$0.0m	$0.0m	$0.0m
Customer initiated	$5.7m	$8.9m	$8.5m	$6.1m	$9.2m	$9.7m	$9.4m	$6.5m	$5.5m	$4.8m
Land acquisition & consents	$2.6m	$0.9m	$0.7m	$0.6m	$0.5m	$1.6m	$0.5m	$0.0m	$0.0m	$0.0m
Future proofing (ducts)	$1.9m	$2.0m	$2.0m	$2.0m	$2.0m	$2.3m	$2.1m	$2.0m	$2.0m	$2.0m
Feeder reinforcements	$8.4m	$8.4m	$8.8m	$12.6m	$13.3m	$11.7m	$7.6m	$7.6m	$6.8m	$5.7m
Power quality reinforcement	$0.4m	$0.4m	$0.4m	$0.4m	$0.4m	$0.6m	$0.5m	$1.6m	$0.8m	$0.4m
Non network solutions	$0.4m	$1.4m	$1.0m	$0.5m	$0.2m	$0.1m	$0.3m	$0.2m	$0.1m	$0.3m
Sub-transmission reinforcement	$0.8m	$3.1m	$2.7m	$4.9m	$7.1m	$4.3m	$0.8m	$0.0m	$1.1m	$4.7m
Total	**$45.1m**	**$45.3m**	**$53.5m**	**$62.6m**	**$52.8m**	**$47.7m**	**$40.6m**	**$42.4m**	**$36.1m**	**$40.6m**

Table 5-34 : Expenditure on growth projects to 2020 broken down by major categories ($millions)

The forecast for relocations and overhead improvement projects is provided in Table 5-35.

Financial Year Ending	Mar 11	Mar 12	Mar 13	Mar 14	Mar 15	Mar 16	Mar 17	Mar 18	Mar 19	Mar 20
Major relocations	$7.7m	$7.1m	$4.9m	$4.2m	$3.8m	$3.6m	$3.6m	$3.6m	$3.6m	$3.6m
Minor relocations	$2.5m	$2.5m	$2.5m	$2.5m	$2.5m	$2.5m	$2.5m	$2.5m	$2.5m	$2.5m
Overhead improvement programme	$12.7m	$12.7m	$12.7m	$12.7m	$12.7m	$12.7m	$12.7m	$12.7m	$12.7m	$12.7m
Total	**$22.9m**	**$22.3m**	**$20.1m**	**$19.4m**	**$19.0m**	**$18.8m**	**$18.8m**	**$18.8m**	**$18.8m**	**$18.8m**

Table 5-35 : Expenditure on relocating assets and overhead improvement projects to 2020 broken down by major categories ($millions)

5.13 Opportunities for Improvement

In preparing our asset management network development plans, the following improvement opportunities have been identified:

- The forecasting process is labour intensive and lends itself to efficiency gain through automation. This will be explored further;
- Changes in consumer behaviour are expected to cause changes to demand characteristics such as load profile, load factor, utilisation factor. There is a need to better reflect these changes in the forecast model;
- The load forecast produces an average year demand projection. This has served the company well in the past. Looking to the future however, the suitability of this approach needs review. It may be appropriate to change the approach to a probabilistic methodology to deal with the uncertain nature of forecasting;
- The quality of data input will have significant impact on the accuracy of the output. Population and employment growth have served well as proxies for demand growth. Other input parameters such as GDP or long term interest rates should perhaps be included to reflect the changing economic conditions;
- The straight-line regression method to determine the starting demand may need to be reviewed. This may include the weighting applied to past demands; and
- Feeder growth is allocated on the percentage length of feeders covering each CAU. This may be revised to reflect the percentage of residential and commercial load in each CAU;
- There is a need to ensure very high security during and in the lead up to the Rugby World Cup. This is being addressed in this asset management planning period;
- Continuing our investigating of non network solutions; and
- It is intended to address these issues during the course of 2011 and progress will be reported in the next AMP.

6. Asset Maintenance, Renewal and Refurbishment Planning

6.1 Overview

This section covers the life cycle asset maintenance, renewal and refurbishment plans and the policies, criteria, assumptions, data and processes used to prepare these.

The foundation of the asset maintenance plan is meeting the customer service targets, which are based on customer type and service expectations. The resulting maintenance refurbishment and replacement strategies for each asset ultimately impact on customer service targets, power quality (PQ), health and safety implications, reliability management and cost.

Vector's distribution network is designed and built to deliver electricity to the service level standards set out in the connection agreements with its customers. In order to achieve this 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 investment and operational costs, 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 our 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 to operating its assets is that they should remain in use for as long as they are safe, technically efficient and economic to do so. The maintenance and refurbishment policies support this goal by actively intervening to ensure optimal asset 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 are expected to exceed that of replacement, (c) there is an imminent risk of asset-failure or (d) assets become obsolete and hence impossible or inefficient to operate and maintain. 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 assets to beyond normal predicted asset life, by servicing or refurbishing the assets.

Asset condition evaluation is based on:

- Vector's field service provider's (FSP's) surveys, observations, test and defect work schedules; 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 service providers. At present this data is not available in a user-friendly form (paper records, for example). For this reason Vector has adopted a Systems Applications and Processes (SAP) based plant maintenance system and a SIEBEL computerised data management system, which will be commissioned in April 2010. Following this, asset condition and replacement data will be directly fed into Vector's databases, based on the activities of our service providers. Vector is also in the process of converting historical asset performance and replacement records into a database format, to allow these to be assessed together with future field-data.

The investigation data, field data and fault records collected and maintained in Vector's databases will be used to conduct asset condition/performance and risk assessments. In future this will better inform our renewal programmes.

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:
  - Ensure the network operation is reliable;
  - Ensure network investments and operating activities are efficient;
  - Maintain the existing assets in good and safe working order until new assets are built or until they are no longer required; and
  - Strive for continual innovation and efficiency improvements in how assets are maintained and operated.

- Customer service:
  - Ensure the safety of the public, our staff and our service providers;
  - Ensure assets are designed, operated and maintained to the required level of standard to provide the targeted level of service; and
  - Ensure an appropriate level of response to customer's concerns, requests and enquiries.
- Cost efficiency:
  - Strive to achieve the optimal balance between capital and operational costs;
  - Co-ordinate asset replacement and new asset creation programmes; and
  - Apply innovative approaches to solutions, development and project execution.

6.2.1 Asset Maintenance Standards and Schedules

Vector's asset maintenance standards are prepared by the AI group – in particular by the integrity teams forming part of the engineering group. Asset inspections and maintenance work are carried out by service providers, 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 that 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 web sites and are available to personnel engaged in maintenance activities, as well as for our service providers. The service providers must comply with the standards and inspection schedules for each class of assets.

The standards are updated on an "as-you-go basis", so that 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 service providers 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. Service providers 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 service providers, 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 a 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 replacement is planned within the next two years, consideration will be given to carrying 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 co-ordinating 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 the wider public are minimised.

Root cause analysis is normally undertaken as a result of faulted equipment. If this identifies systemic faults or performance issues with a particular type of asset, and if the risk exposure warrants it, a programme 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 analyses.

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 groups) is defined in the maintenance standards, flowing through into the contractors' schedule;
- Corrective maintenance work is the work that flows from the preventative activities, site inspections, testing and observations by Vector's contractors 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 encapsulates 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

Preventative Maintenance covers activities that are defined in 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.

The table below provides a summary of preventative maintenance activities by asset class, together with appropriate standards and document references.

Asset Class / Category	Activity Standard	Preventative Maintenance Description
Auto Transformer - Zone Substation	ENS – 0193	2 yearly - Oil condition sample
Battery Bank - POS Substation	ENS - 0171	6 monthly - Battery bank discharge testing
Battery Bank - Zone & POS Substation	ENS – 0171	2 monthly - Battery bank and charger visual inspection and functional testing
	ENS – 0171	annual - Battery charger testing
Battery Bank - Zone Substation	ENS – 0171	annual - Battery bank discharge testing
Building and Grounds - POS Substation	ENS – 0189	annual - Alarms testing and compliance assessment
	ENS – 0189	annual - Electrical assets partial discharge assessment
Building and Grounds - Zone & POS Substation	ENS - 0189	2 monthly - Building services visual inspection and condition assessment
	ENS - 0189	2 monthly - Electrical assets visual inspection
	ENS - 0189	3 weekly - Grounds inspection and vegetation service
	ENS - 0189	annual - Electrical assets thermal camera inspection
Building and Grounds - Zone Substation	ENS - 0189	monthly - Building compliance assessment
	External Procedure	annual - Building warrant of fitness certification
Capacitor Banks - Zone Substation	ENS - 0192	2 monthly - Visual inspection
	ENS - 0192	2 yearly - Visual inspection and testing
	ENS - 0192	4 yearly - Maintenance service
Capacitor Bank - Overhead	ENS - 0048	8 yearly - Visual inspection
	ENS - 0068	5 yearly - Earth system visual inspection and testing
Circuit Breaker - POS Substation	ENS - 0049	8 yearly - Outdoor vacuum/ SF_6 circuit breaker maintenance service
Circuit Breaker - Zone & POS Substation	ENS - 0049	2 yearly - Circuit breaker trip timing and voltage testing
	ENS - 0049	4 yearly - Outdoor oil circuit breaker maintenance service
Circuit Breaker - Zone Substation	ENS - 0049	12 yearly - Indoor vacuum/ SF_6 circuit breaker maintenance service
	ENS - 0049	16 yearly - Switchboard maintenance service
	ENS - 0049	2 yearly - Switchboard partial discharge assessment
	ENS - 0049	4 yearly - Outdoor vacuum/ SF_6 circuit breaker maintenance service
	ENS - 0049	8 yearly - Indoor oil circuit breaker maintenance service

Asset Class / Category	Activity Standard	Preventative Maintenance Description
Earthing - POS Substation	ENS - 0076	6 monthly - Earth system visual inspection
	ENS - 0076	annual - Earth system visual inspection and testing
Earthing - Zone & POS Substation	ENS - 0076	annual - Temporary earthing equipment visual inspection and testing
Earthing - Zone Substation	ENS - 0076	5 yearly - Earth system visual inspection and testing
	ENS - 0076	annual - Earth system visual inspection
Fault Passage Indicator - Overhead	ENS - 0075	5 yearly - Visual inspection and testing
Fire Suppression Systems - Zone Substation	ENS - 0195	6 monthly - visual inspection and functional testing
	ENS - 0195	annual - visual inspection and functional testing
	ENS - 0195	monthly - visual inspection and functional testing
GM Substation - Distribution Substation	ENS - 0051	4 yearly - Transformer visual inspection, thermal camera inspection and partial discharge assessment
	ENS - 0052	4 yearly - Switchgear visual inspection, thermal camera inspection, partial discharge assessment and oil condition sample
	ENS - 0053	4 yearly - Building/Enclosure visual inspection
	ENS - 0068	5 yearly - Earth system visual inspection and testing
HV Customer Substation - Distribution Substation	ENS - 0049	12 yearly - Vacuum/ SF_6 circuit breaker maintenance service
	ENS - 0049	2 yearly - Circuit breaker trip timing and voltage testing
	ENS - 0049	8 yearly - Oil circuit breaker maintenance service
	ENS - 0051	4 yearly - Transformer thermal camera inspection and partial discharge assessment
	ENS - 0051	annual - Transformer visual inspection
	ENS - 0052	4 yearly - Switchgear thermal camera inspection, partial discharge assessment and oil condition sample
	ENS - 0052	annual - Switchgear visual inspection
	ENS - 0053	annual - Building/Enclosure visual inspection
	ENS - 0068	5 yearly - Earth system visual inspection and testing

Asset Class / Category	Activity Standard	Preventative Maintenance Description
	ENS - 0171	annual - Battery bank inspection and testing
	ENS - 4001	4 yearly - Electromechanical protection relay functional testing
	ENS - 4001	4 yearly - Numerical protection relay functional testing
Load Transfer Scheme - Sub-transmission	Internal Procedure	annual - visual inspection and functional testing
Oil Containment System - Zone Substation	ENS - 0198	2 monthly - Plate separator and interception tank visual inspection
	ENS - 0198	annual - Plate separator maintenance service and functional testing
Overhead Structures - Zone Substation	ENS - 0190	annual - Outdoor Buswork and bus structure visual inspection
Overhead Switchgear - Zone Substation	ENS - 0190	3 yearly - Air break switch (ABS) maintenance service
Pilot Cable - Comms and SCADA	Internal Procedure	2 yearly - SCADA communication cable functional testing
Pits and Pillars - LV Distribution	ENS - 0175	3 yearly - Visual inspection
Power Transformer - Zone Substation	ENS - 0193	2 yearly - Transformer primary protection relay functional testing
	ENS - 0193	4 yearly - Automatic voltage regulator relay functional testing
	ENS - 0193	annual - Tap changer oil condition sample
	ENS - 0193	annual - Transformer oil condition sample
	Internal Procedure	4 yearly - Winding/Oil temperature measurement functional testing and recalibration
Protection Relays - Zone & POS Substation	ENS - 4001	12 yearly - Static protection relay functional testing
	ENS - 4001	4 yearly - Electromechanical protection relay functional testing
	ENS - 4001	8 yearly - Numerical protection relay functional testing
Radio Link - Comms and SCADA	Internal Procedure	annual - signal strength testing and visual assessment
Radio Repeater - Comms and SCADA	Internal Procedure	annual - Building/Enclosure visual inspection
	Internal Procedure	annual - signal strength testing and visual assessment
Recloser - Overhead	ENS - 0058	9 Yearly - Recloser maintenance service
	ENS - 0068	5 yearly - Earth system visual inspection and testing
Ripple Plant - Zone & POS	ENS - 4003	4 yearly - Injection signal assessment and testing

Asset Class / Category	Activity Standard	Preventative Maintenance Description
Substation		
	ENS - 4003	annual - Injection assets maintenance service
	ENS - 4003	annual - Under frequency load shedding functional testing
SCADA - Comms and SCADA	Internal Procedure	2 yearly - Zone and POS substation RTU visual inspection and functional testing.
Structures and Lines - Overhead	ENS - 0057	10 yearly - Concrete structure load v strength assessment
	ENS - 0057	10 yearly - Wooden structure load v strength assessment
	ENS - 0057	5 yearly - Wooden structure load v strength assessment
	ENS - 0187	annual - Visual inspection
Sub-transmission Cable - Sub-transmission	ENS - 0196	2 yearly - cable serving testing
	ENS - 0196	2 yearly - cross bonding link box visual inspection
	ENS - 0196	5 yearly - cable surge voltage limiter visual inspection and testing
	ENS - 0196	annual - cable termination thermal camera inspection
	ENS - 0196	annual - Visual inspection of cable within accessible tunnels
	ENS - 0196	weekly - circuit patrol, visual inspection
Sub-transmission Tunnel - Sub-transmission	ENS - 0197	annual - Visual inspection of cable tunnel structure
Switchgear - Overhead	ENS - 0055	3 yearly - Air-break switch maintenance service
	ENS - 0055	3 yearly - Thermal Camera Inspection
	ENS - 0055	9 yearly - Gas-break switch visual inspection
	ENS - 0068	5 yearly - Earth system visual inspection and testing
Transformer - Overhead	ENS - 0051	5 yearly - Visual inspection
	ENS - 0068	5 yearly - Earth system visual inspection and testing
Voltage Regulator - Overhead	ENS - 0061	5 yearly - Visual inspection, thermal camera image, oil condition sample and functional testing
	ENS - 0068	5 yearly - Earth system visual inspection and testing
Voltage Transformer - Zone Substation	ENS - 0049	4 yearly - Outdoor voltage transformer visual inspection and maintenance service
	ENS - 0049	8 yearly - Indoor voltage transformer visual inspection and maintenance service

Table 6-1 : Preventative maintenance schedules and standards

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, work site observer, urgent safety checks, safety disconnections;
- Issuing close approach permits, high load permits, high load escorts; and
- Disconnection and reconnection associated with customers' property movements and any concerns relating to non-compliance with 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.

Currently, work undertaken and costs associated with the maintenance work is not readily captured per asset or asset group. This will change in future, with the commissioning of the SAP Plant Maintenance module (SAP-PM) – creating a technical asset master (TAM), scheduled for April 2010. The report format in Table 6-2 below will enable Asset Investment (AI) to capture work and costs associated per asset as well as per maintenance category (preventative, corrective and reactive). The report will be generated from the TAM system.

Asset Reference		Preventive MTCE			Corrective MTCE		Reactive MTCE		Total MTCE
Asset ID	Category	Activity ID	Description	Costs	Description	Costs	Description	Costs	Costs

Table 6-2 : Monthly maintenance activity report sheet

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 SD to keep abreast of any issues with regards to the contractors' obligations and performance. The maintenance standards form part of the maintenance contract with which contractors must comply when performing their duties.

The chart in Figure 6-1 : Asset maintenance processes below describes the flow of work and responsibilities in maintaining Vector's assets.

AI has developed an internal monthly report sheet to capture information on the conditions and performance of the assets, and work and costs of the maintenance undertaken per asset or asset group. The report will enable AI to better understand the physical condition and performance of the assets and to update Vector's asset performance records. It will also better inform the preparation of future asset renewal programmes.

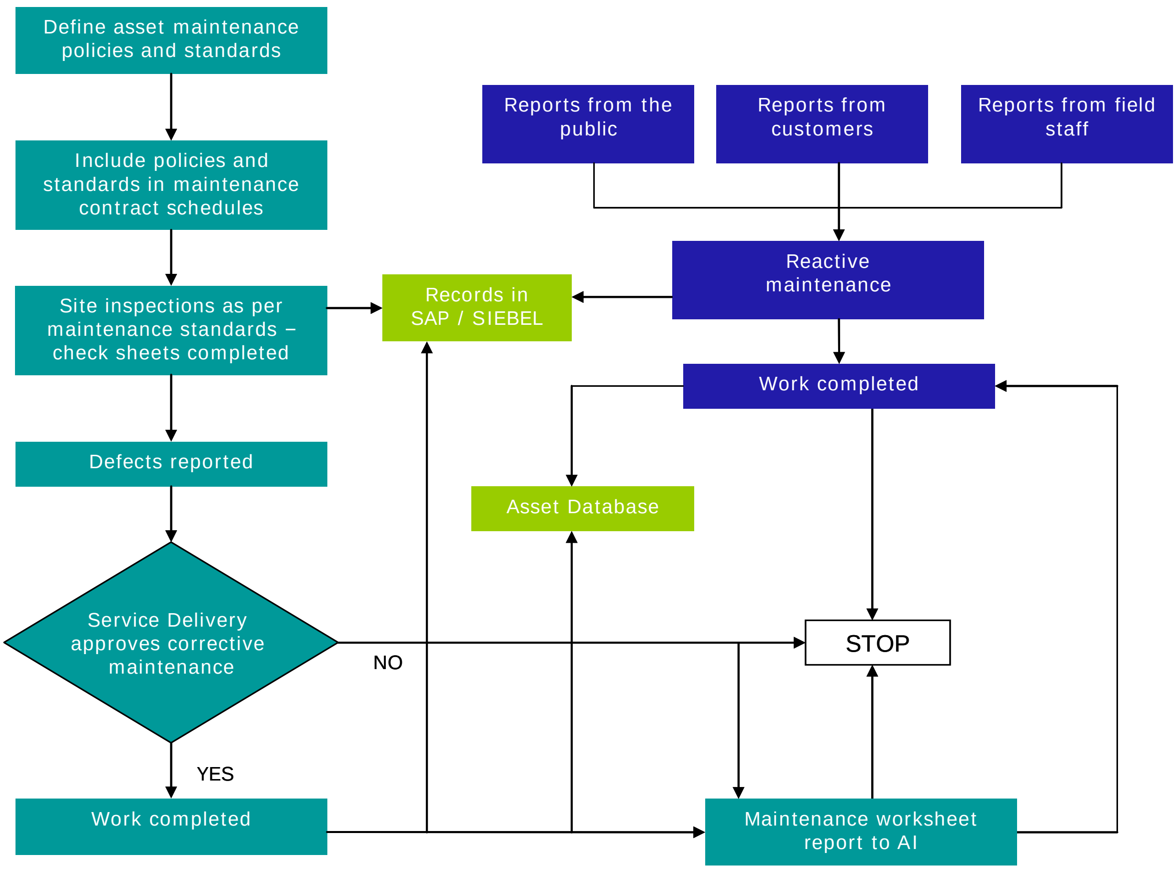


Figure 6-1 : Asset maintenance processes

6.2.4 Summary of Forecast Maintenance Budgets

Table 6-3 provides Vector's maintenance budget forecasts for the next ten years by activity (in real terms).

Fiscal Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Preventive	13.7 M	13.7 M	13.7 M	13.7 M	13.7 M	13.7 M	13.7 M	13.7 M	13.7 M	13.7 M
Renewal	11.8 M	11.8 M	11.8 M	11.8 M	11.8 M	11.8 M	11.8 M	11.8 M	11.8 M	11.8 M
Emergency	14.9 M	14.9 M	14.9 M	14.9 M	14.9 M	14.9 M	14.9 M	14.9 M	14.9 M	14.9 M
Total	40.3	40.3	40.3	40.3	40.3	40.3	40.3	40.3	40.3	40.3

Table 6-3 : Summary of maintenance budget forecast (fiscal years from 1 July to 30 June)

As noted before, Vector does not currently have sufficiently disaggregated historical information to easily trace maintenance expenditure per asset category. In future, after commissioning the TAM system in April 2010, the service providers will be providing data and costs per asset and per activity directly on to Vector's SAP system.

6.3 Asset Integrity Activities

In this section the details of Vector's asset base are provided, along with inspection, refurbishment and renewal programmes for each major asset category.

6.3.1 Sub-Transmission Cable

The total Vector sub-transmission network consists of 563km of cables operating at 110kV, 33kV and 22kV with a book value of $219 million. A breakdown per cable type is provided in Table 6-4 below and the age profile per network is indicated in Figure 6-2 and Figure 6-3.

Cable Type	110kV	33kV	22kV	Total
PILC	0 km	18 km	64 km	82 km
XLPE	28 km	226 km	35 km	288 km
Oil Pressurised	17 km	127 km	23 km	167 km
Gas Pressurised	20 km	0 km	6 km	26 km
Total	**65 km**	**371 km**	**126 km**	**563 km**
Population	110kV	33kV	22kV	Total
Southern	65 km	242 km	126 km	434 km
Northern	0 km	129 km	0 km	129 km
Total	**65 km**	**371 km**	**126 km**	**563 km**
Book Value	110kV	33kV	22kV	Total
Southern	$ 52.3 m	$ 95.3 m	$ 31.3 m	$ 179.0 m
Northern	$ 0.0 m	$ 39.7 m	$ 0.0 m	$ 39.7 m
Total	**$ 52.3 m**	**$ 135.1 m**	**$ 31.3 m**	**$ 218.7 m**

Table 6-4 : Sub-transmission cable population and book value

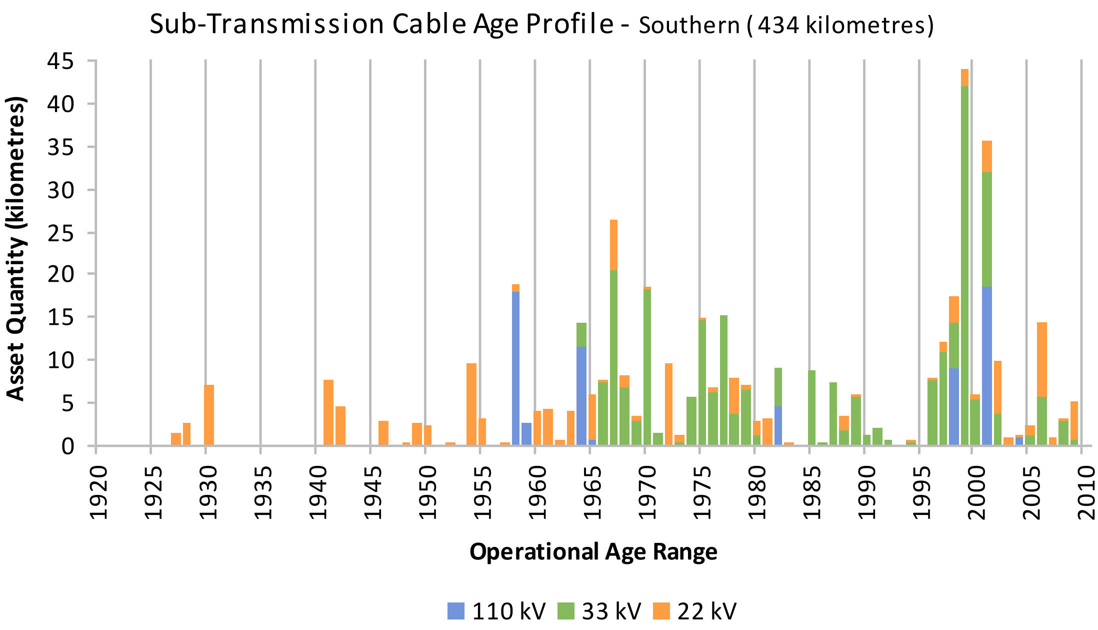


Figure 6-2 : Sub-transmission cable age profile - Southern

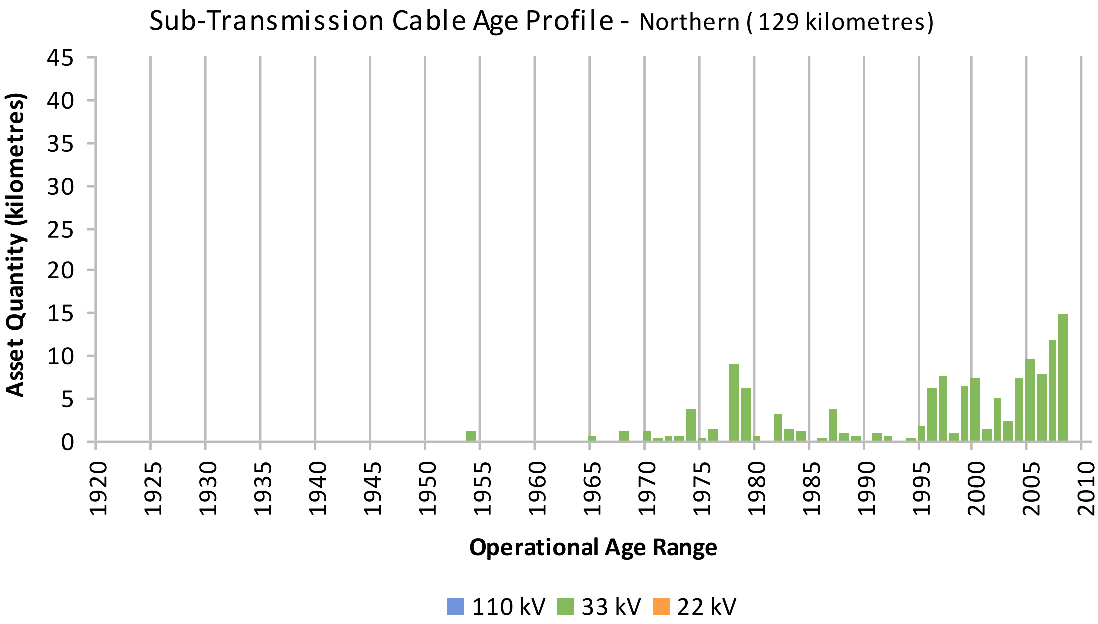


Figure 6-3 : Sub-transmission cable age profile - Northern

The book value by cable type and network area is shown in Figure 6-4 and Figure 6-5

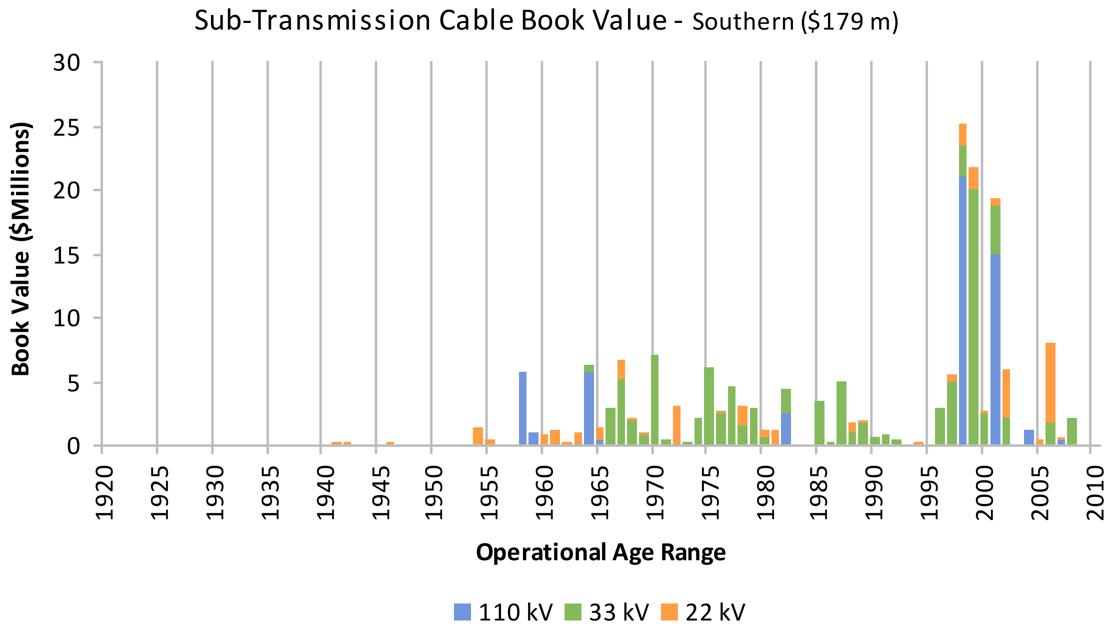


Figure 6-4 : Sub-transmission cable book value - Southern

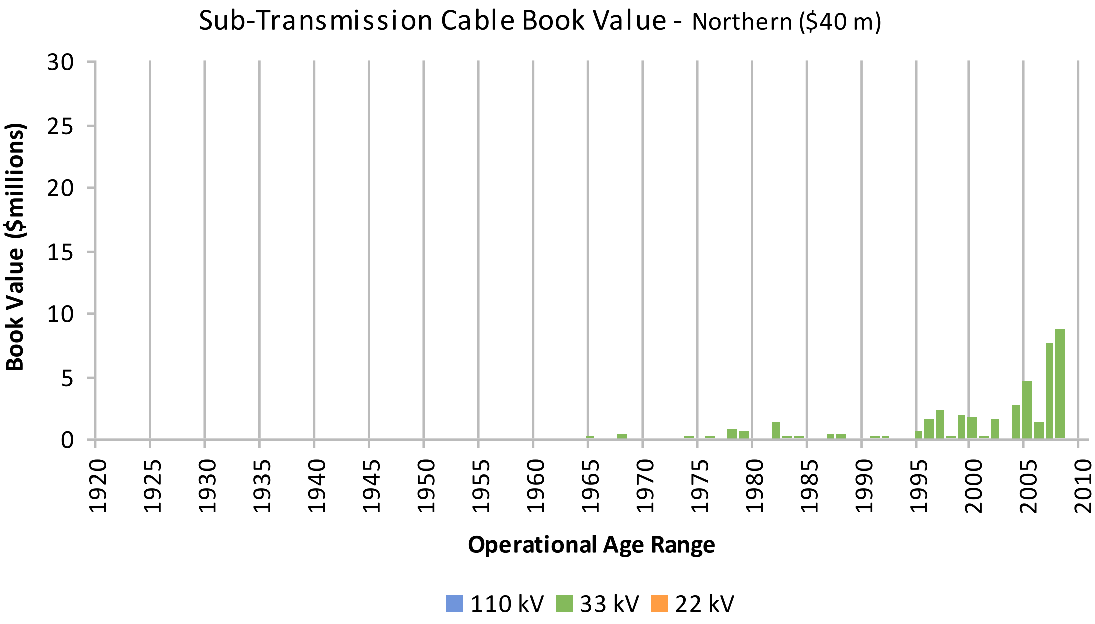


Figure 6-5 : Sub-transmission cable book value - Northern

6.3.1.1 Asset Condition by Construction Type

- Paper insulated lead cables (PILC)

  Approximately 82km of 22kV and 33kV PILC type cables were installed on the Vector network between the early 1920's and late 1980's.

  The cables are generally in good to very good condition. Failures on this type of cables are usually caused by joint failure or as a result of third party damage. A number of the earlier cables were laid on private property and when faults develop these can prove difficult to access due to concerns raised by the private land owners. The least reliable cables will be progressively replaced over the next ten years. Others will be replaced as their failure rate increases or ratings can no longer meet network requirements.

- Fluid filled cables (FF cables)

  There is approx 167km of 110kV, 33kV and 22kV fluid filled cables (FF cables) installed on the Vector network, with all but 3km being on the Southern network. These cables were installed between 1964 and 1990 and are generally in very good condition. All FF cables have their fluid pressure closely monitored and alarmed via the SCADA system so as to quickly 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 a 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 to Maraetai 33kV) will 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 taking certain cables out of service. In such cases the leak is managed so that the cable can be kept in service for as long as possible without compromising its integrity and risking electrical failure. Figure 6-6 below shows the sub-transmission cable fluid consumption over the past six years.

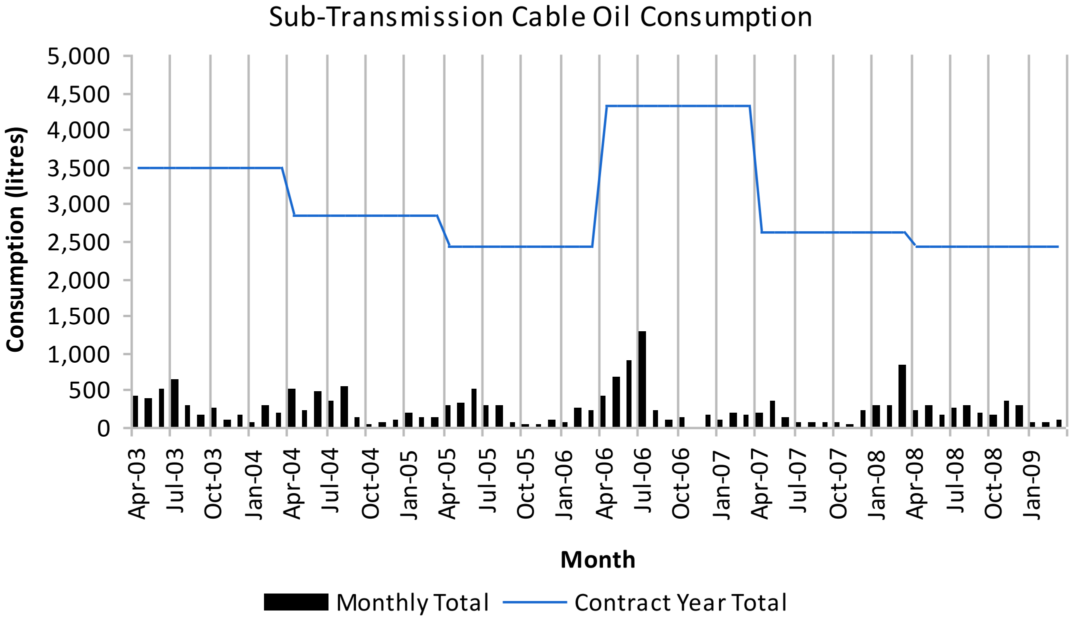


Figure 6-6 : Sub-transmission cable fluid consumption

- XLPE cables

There is approximately 288km of 110kV, 33kV and 22kV XLPE installed across both networks. XLPE at sub-transmission level was only introduced on to the Southern network in 1996, so the problems experienced worldwide with water treeing in the earlier (1960s and 70s) cables, have been avoided, and 165km of these cables are in very good condition. However, five 33kV circuits with possibly incorrectly installed joints have caused problems over the past nine years (Risk AIAE3020). All joints on two of these circuits have been replaced, but due to their locations and the back fill material used, the other circuits are being closely monitored and tested and will be replaced if their condition deteriorates or they fail.

The 123km 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.

- Gas pressurised cables

  There are now only four circuits of this type of cable 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 commissioned in 1958 and the joints, of which there are more than 100, are now proving unreliable with a number of failures over the past three years due to pulled ferrules. A project is under way to provide an alternative 110kV supply circuit (Liverpool to Quay substation) to ensure that Vector's service levels in the CBD can be met without relying on the gas pressurised cables. Final retirement of these old cables will be in 2013 when the major supply reinforcement to the CBD (through installing a new GXP at Hobson Street substation) is scheduled to be completed. In the meantime they will be kept on standby – offering additional flexibility to the CBD bulk supply network. The other two circuits operate at 22kV and 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 PD testing, to gain an early indication of any problems. Other circuits are tested in accordance with the routine frequency specified in our standard.

6.3.1.3 Replacement Programme

The timing for the replacement of sub-transmission cables is generally based on condition, performance, ratings and industry wide failure information. However, it can also result from non-electrically related drivers such as relocation due to other infrastructure development (roading re-alignment, railway corridors, bridges, private land issues, etc).

Maintenance history, fault repairs and associated costs to the networks (SAIDI/SAIFI impact) and analysis of risk profiles have identified several cables that are due for replacement. Replacing these circuits represents a significant investment, but keeping them in operation would pose an unacceptable level of risk to the network[33]. A summary of the anticipated sub-transmission cable replacement projects (subject to ongoing performance measurement) for the next six years is given in the table below.

Asset Description	Circuit Length	Replacement Year	Estimated Cost
Sandringham 22kV	2.5km	2010	$5.0 million
Balmoral 22kV	2.0km	2011	$3.5 million
Maraetai (FF) 33kV	5.0km	2012	$7.0 million
Parnell 22kV	1.8km	2013	$3.0 million
Ponsonby 22kV	2.5km	2014	$4.0 million
Chevalier 22kV	3.4km	2015	$5.0 million
Liverpool–Quay 22kV	2.0km	2016	$4.0 million

Table 6-5 : Planned sub-transmission cable replacement projects

[33] The requirement for replacing the old 22kV sub-transmission cables was also identified by Siemens GmbH in an independent assessment carried out by them in 2009 on the robustness of asset management at Vector.

6.3.2 Power Transformers

Vector owns 198 sub-transmission power transformers, including two at Lichfield which lies outside of Vector's main supply network. The transformers have been manufactured by 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 approximately $80 million. There are 16 transformers with a primary voltage of 110kV, 139 at 33kV and 43 at 22kV ranging in rating from 5MVA to 65MVA. The majority of these transformers are fitted with on-load tap-changers. Table 6-6 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	11	66	43	120
Northern	3	73	0	76
Total	**14**	**139**	**43**	**196**

Book Value	110kV	33kV	22kV	Total
Southern	$10.3m	$27.9m	$15.8m	$54.0m
Northern	$2.3m	$21.2m	$0.0m	$23.5m
Total	**$12.6m**	**$49.2m**	**$15.8m**	**$77.5m**

Table 6-6 : Sub-transmission transformers - population and book value

The age profiles of the sub-transmission transformers are shown in Figure 6-7 and Figure 6-8.

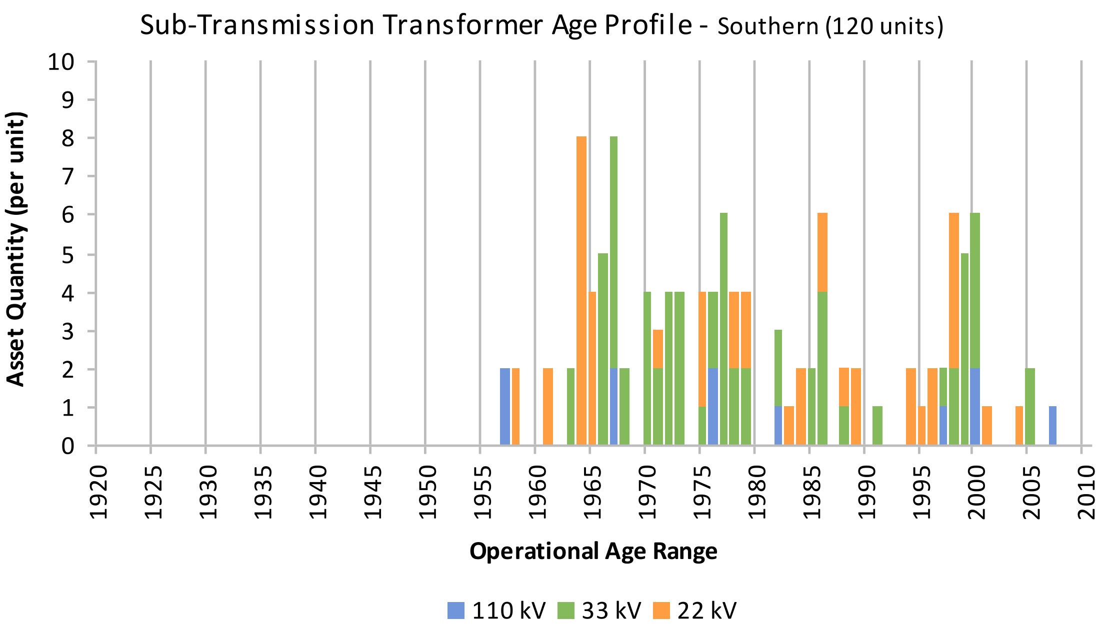


Figure 6-7 : Sub-transmission transformer age profile – Southern

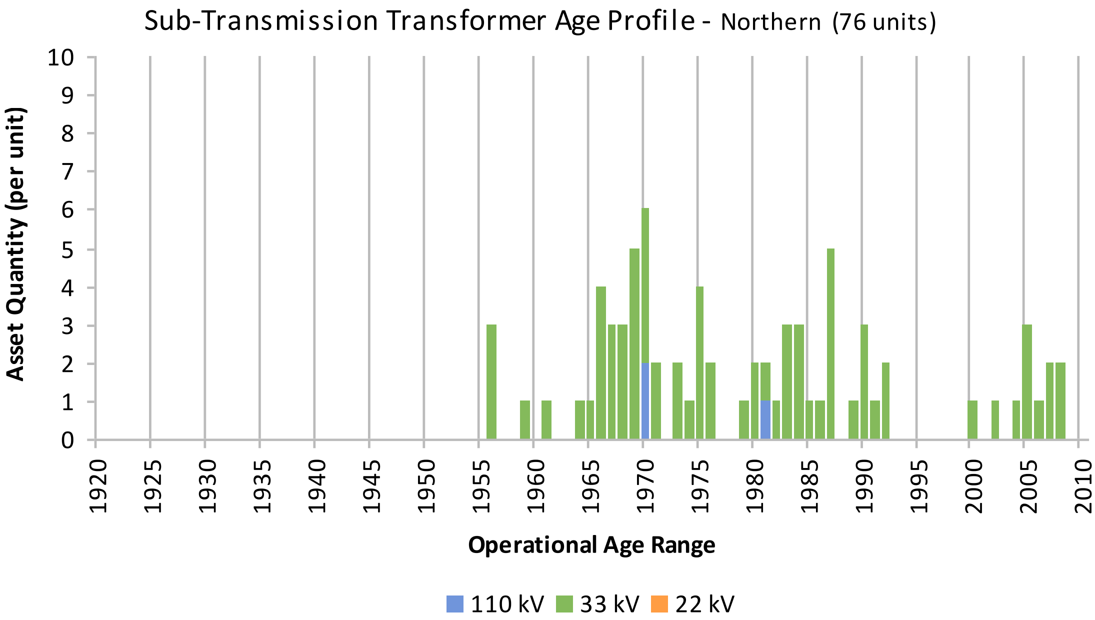


Figure 6-8 : Sub-transmission transformer age profile – Northern

The book values by transformer primary voltage and year installed for each network area are shown in Figure 6-9 and Figure 6-10.

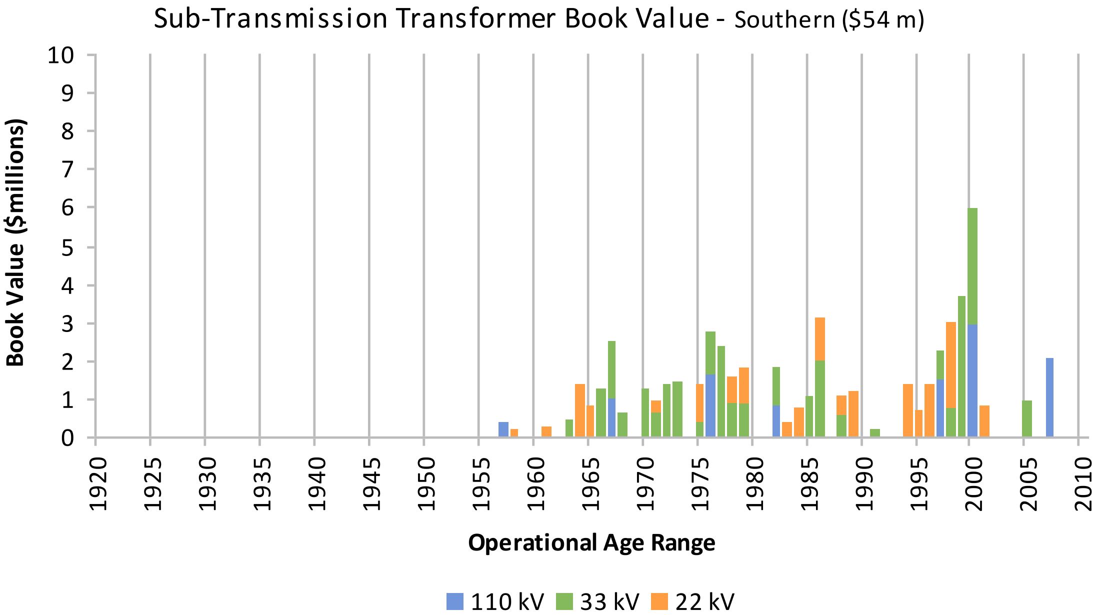


Figure 6-9 : Sub-transmission transformer book value - Southern

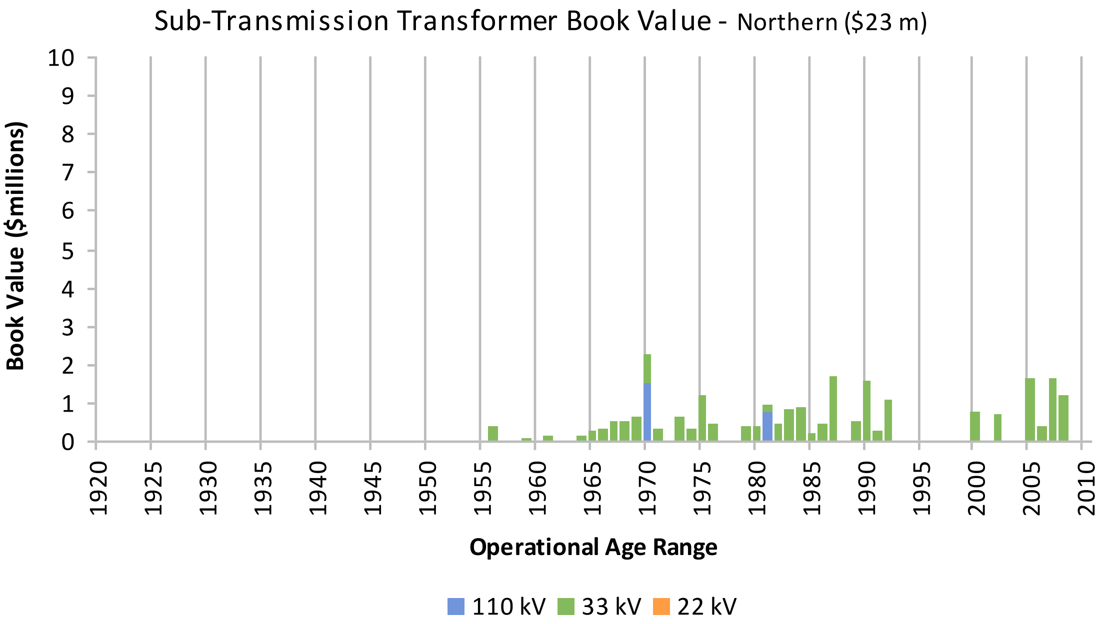


Figure 6-10 : Sub-transmission transformer book value - Northern

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 Replacement Programme

The transformer population is in good condition overall but there are a small number where a degree of polymerisation (DP) 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 it is anticipated that one transformer on each network will be replaced every second year for the next several years. Two new power transformers are on order to replace old units at Liverpool substation during FY2011. The table below shows the budgeted replacement costs over the next six years.

Asset Description	No of Units	Replacement Year	Estimated Cost
Liverpool 110/22kV	2	2011	$7.5m
TBA	1	2012	$2.2m
TBA	1	2014	$2.2m
TBA	1	2016	$2.2m

Table 6-7 : Sub-transmission transformer replacement projects by year

Vector is currently gathering TCAs on the entire fleet of power transformers. The test results will be used to determine the condition of all the transformers on the networks, to rank them for replacement or refurbishment as necessary. Replacements for future years denoted with "TBA" will be specifically identified once the entire fleet test results have been collated and ranked. With this process, units in the poorest condition will be identified and prioritised for replacement. Vector anticipates having complete TCAs on all units by the end of the 2011 financial year. (Since Vector does not replace assets on age-considerations, the outcome of the test results may allow replacements to be deferred).

6.3.2.2 Operating Conditions

The engineering design life of a power transformer is 30 to 40 years. However, provided that 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 not be exceeded:

- Top oil temperature - 105 ºC;
- Conductor hot-spot temperature - 125 ºC; and
- Metallic part temperature - 135 ºC.

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 our knowledge of and confidence in 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, moisture in insulation, DGAs, oil leaks, age, and so on, and should be in place during the 2011 financial year.

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 and ENS-0106 for outdoor stand alone CBs. Vector's sub-transmission switchgear comprises oil, SF_6 and resin insulated equipment of varying ages and manufacturers. 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 6-8 shows the current number of and value of CBs on the networks categorised by operating voltage.

Population	110kV	33kV	22kV	11kV	6.6kV	Total
Southern	11	19	107	775	24	936
Northern	0	245	0	412	0	657
Total	**11**	**264**	**107**	**1187**	**24**	**1593**

Book Value	110kV	33kV	22kV	11kV	6.6kV	Total
Southern	$11.0m	$0.5m	$2.1m	$11.9m	$0.4m	$25.9m
Northern	$0.0m	$7.7m	$0.0m	$7.2m	$0.0m	$14.9m
Total	**$11.0m**	**$8.2m**	**$2.1m**	**$19.1m**	**$0.4m**	**$40.8m**

Table 6-8 : Sub-transmission switchgear – population and book value

The CBs on the Vector electricity network range from new to over 50 years old. 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 6-11 and Figure 6-12 show the age profile of CBs and switchboards in the Southern and Northern regions.

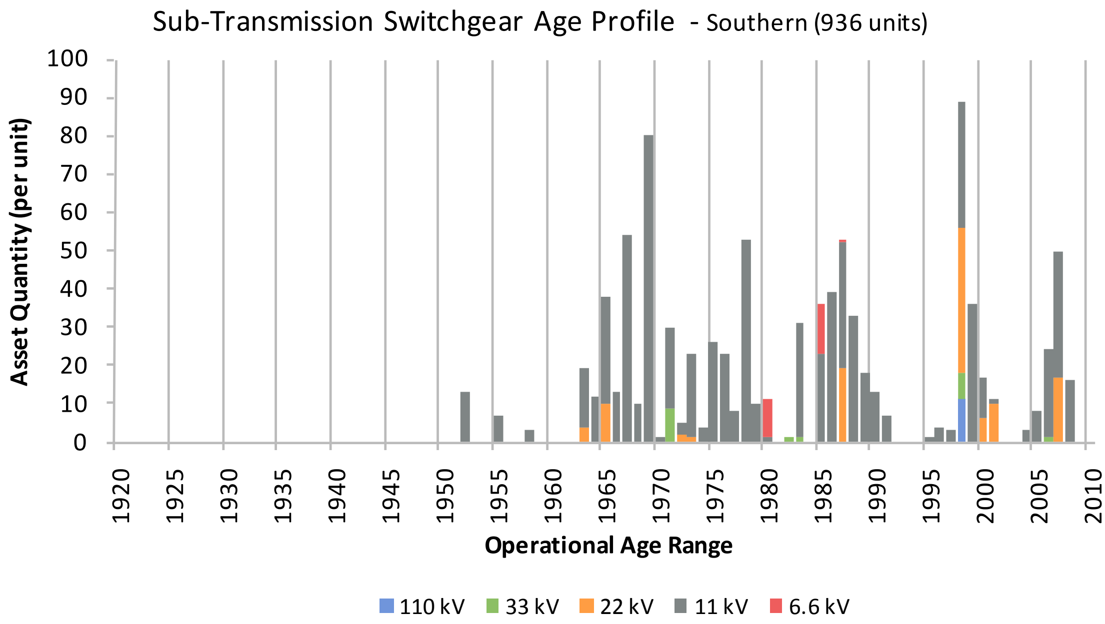


Figure 6-11 : Sub-transmission switchgear age profile – Southern

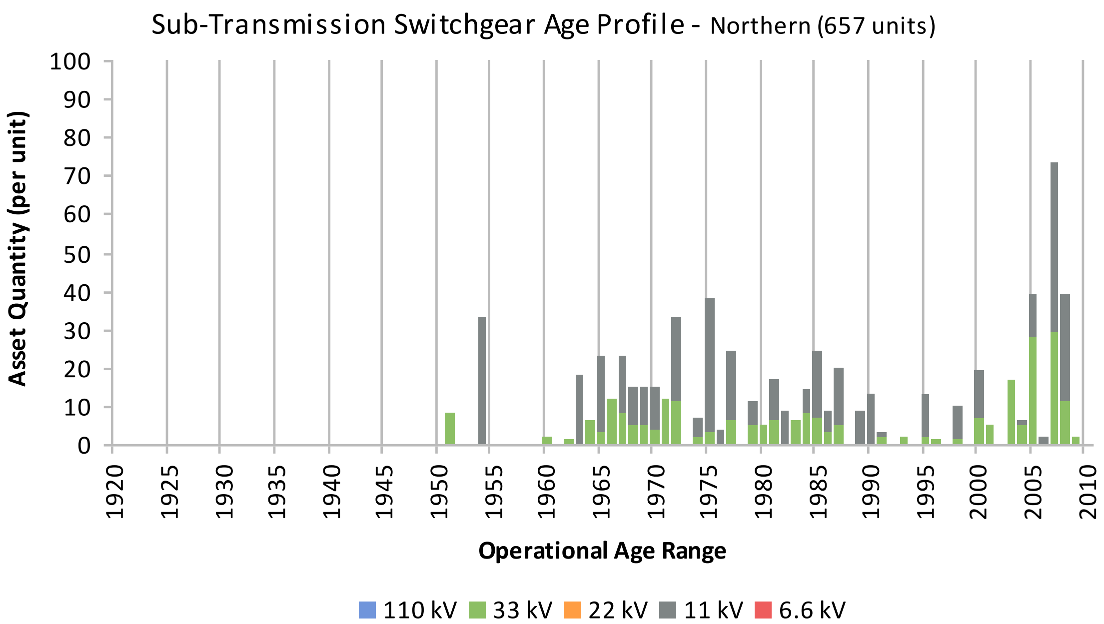


Figure 6-12 : Sub-transmission switchgear age profile – Northern

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 33kV 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 110kV GIS switchboard at Auckland's Liverpool substation; and
- Two outdoor 110kV GIS CBs and associated ABS' and outdoor bus works at the Lichfield substation (Fonterra Cheese Factory). Ownership of these two CBs has been assigned to Transpower for the duration of the connection contract.

The OCBs are the oldest in the network and constitute 75% of the total number of CBs followed by SF_6 at 13% and vacuum at 12%. CB technology using Vacuum or SF_6 interrupters and SF_6 gas insulated equipment is primarily technology of the past 20 years. Until this time, minimum oil volume (MOV) and bulk OCB dominated the market.

Figure 6-13 and Figure 6-14 show the book value of CBs on the Southern and Northern networks.

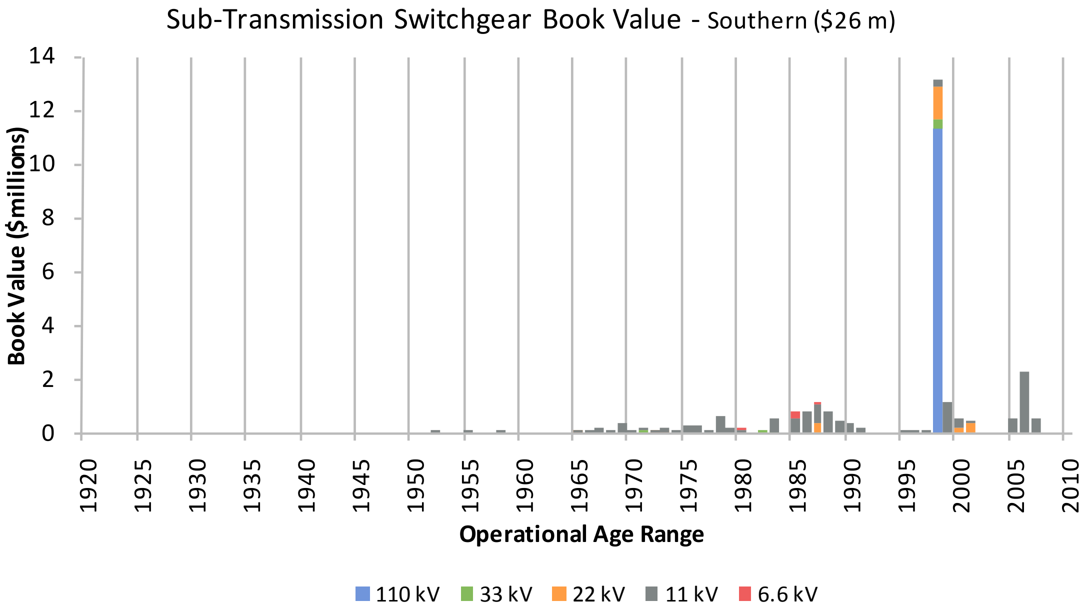


Figure 6-13 : Sub-transmission switchgear book value - Southern

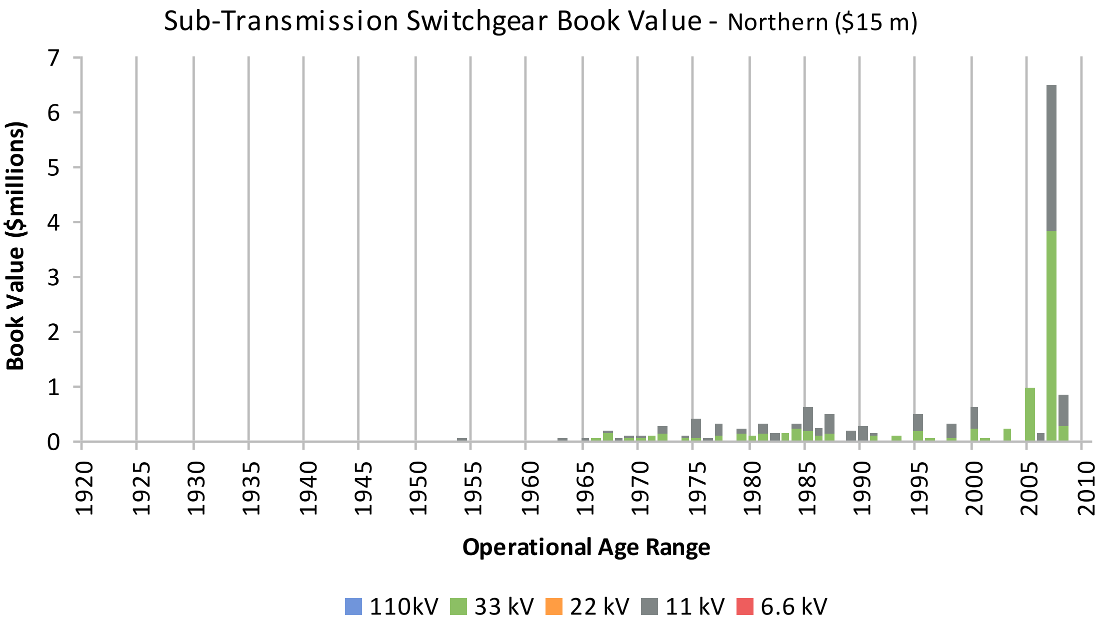


Figure 6-14 : Sub-transmission switchgear book value - Northern

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 is 35 years and all outdoor CBs 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 CBs and ENS-0165 for outdoor ABS'. 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. They are in very 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 that the equipment requires service. Under normal operating conditions, experience shows that only a catastrophic failure of the tank or seals will 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 an explosion - 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, 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 VCBs have proven to be more reliable, as expected given their more modern manufacturing techniques and higher equipment specifications. The metal clad portions consist of powder coated galvanised and stainless steel are not expected to show the same signs of metal fatigue as apparatus that was produced up to the late 1980s.

New switchboard installations and outdoor CBs of the last six years comply with Vector specifications ENS-0005 and ENS-0106 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).

6.3.3.2 Maintenance Programme

Asset maintenance criteria including inspection, testing and condition assessment are set 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 CBs. 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 CBs require more frequent inspection than others);
- Annual thermographic examination of substation equipment;
- Annual PD testing and monitoring;
- 'Kelman' profile testing and non-invasive PD location and monitoring is carried out on a two-year cycle;
- Major maintenance on the switchgear, including inspection and testing of CBs 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 the English Electric type OLX switchboards, 33kV ORT2 CBs and Motorpol supplied 36PV25 (Crompton Greaves) CBs have been identified as being due for replacement.

As noted above, new equipment purchased under Vector specification ENS-0005 for growth areas or replacement, is of the maintenance free fit for life category. 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 oil and 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;
  - 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;
  - 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; and
  - 12 yearly - indoor vacuum/SF6 CB maintenance service.
- 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 indentified 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, but 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 requirements) 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 in the process of implementing.

As noted above, the continued use of old oil-filled switchgear (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 was required (e.g. Otara substation, which is undergoing a seven panel VCB extension to the existing Reyrolle LMT switchboard). To reduce the risk of damage to this new section of 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 will continue with this practice in future where there are existing combinations of OCBs and VCBs that need upgrading.

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. 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.

Table 6-9 below lists the switchboards and CBs identified for replacement over the next five years.

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 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 precast 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 to reduce costs as some of the aesthetic treatments are not required.

Vector has also begun a process of evaluating the long-term requirements of the more rural aged substations with a view to convert the outdoor yards where it is economically viable. Vector plans to redevelop Swanson substation this year with a replacement of the outdoor 33kV infrastructure with a containerised indoor switchboard. The container, albeit industrial in design, is in keeping with the existing station while at the same time improving the visual outlook of the old outdoor apparatus.

The remainder of 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.

Project Description	Network	Replacement Year	Estimated Cost
33kV Outdoor Replace - Wellsford	Northern	2011	$0.25 m
11kV Indoor Retrofit - Avondale	Southern	2011	$0.55 m
11kV Indoor Replace - Sabulite	Northern	2011	$1.80 m
11kV Indoor Replace - Wairau Valley	Northern	2011	$3.00 m
33kV Outdoor Replace - Belmont	Northern	2012	$0.38 m
11kV Indoor Retrofit - Carbine	Southern	2012	$0.55 m
11kV Indoor Retrofit - Belmont	Northern	2012	$0.55 m
11kV Indoor Replace - New Lynn	Northern	2012	$1.80 m
11kV Indoor Replace - Maraetai	Southern	2012	$2.50 m
11kV Indoor Replace - Liverpool Stage I	Southern	2012	$3.00 m
33kV Indoor Replace - Wairau Valley	Northern	2012	$5.00 m
33kV Outdoor Replace - Helensville	Northern	2013	$0.25 m
11kV Indoor Retrofit - Chevalier	Southern	2013	$0.55 m
11kV Indoor Retrofit - Birkdale	Northern	2013	$0.55 m
11kV Indoor Replace - Browns Bay	Northern	2013	$1.80 m
11kV Indoor Replace - Liverpool Stage II	Southern	2013	$3.00 m
22kV Indoor Replace - Kingsland	Southern	2013	$4.00 m
11kV Indoor Retrofit - Greenmount	Southern	2014	$0.15 m
11kV Indoor Retrofit - Hans	Southern	2014	$0.40 m
11kV Indoor Retrofit - Henderson Valley	Northern	2014	$0.55 m
33kV Outdoor Replace - Sabulite	Northern	2014	$0.63 m
11kV Indoor Replace - Riverhead	Northern	2014	$1.00 m
11kV Indoor Replace - Milford	Northern	2014	$1.00 m
11kV Indoor Replace - Balmain	Northern	2014	$1.00 m
11kV Indoor Replace - Laingholm	Northern	2014	$1.00 m
11kV Indoor Replace - Onehunga	Southern	2014	$2.10 m
11kV Indoor Replace - Balmoral	Southern	2014	$2.10 m
11kV Indoor Replace - Orakei	Southern	2015	$2.10 m
11kV Indoor Replace - Manurewa	Southern	2015	$2.10 m
11kV Indoor Retrofit - Hobson	Southern	2015	$0.55 m
11kV Indoor Retrofit - Hillcrest	Northern	2015	$0.55 m
33kV Outdoor Replace - Browns Bay	Northern	2015	$0.31 m
33kV Outdoor Replace - Waikaukau	Northern	2015	$0.31 m

Table 6-9 : Planned replacement and retrofitting of switchboards and CBs

Table 6-10 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 Lichfield where supply is directly taken from Transpower at 110kV).

Network	Population	Book Value
Southern	55	$66.7m
Northern	50	$48.5m
TOTAL	**105**	**$95.2m**

Table 6-10 : Primary Substation land and buildings – population and book value

The substation buildings range from new to 62 years old on the Southern region and from new to 53 years old on the Northern region. In all there are 105 in service zone substations and switching stations, with an additional four zone substations currently under construction.

Figure 6-15 and Figure 6-16 show the age profile of zone substation buildings in the Southern and Northern regions. The book-value of the assets is given in Figure 6-17 and Figure 6-18.

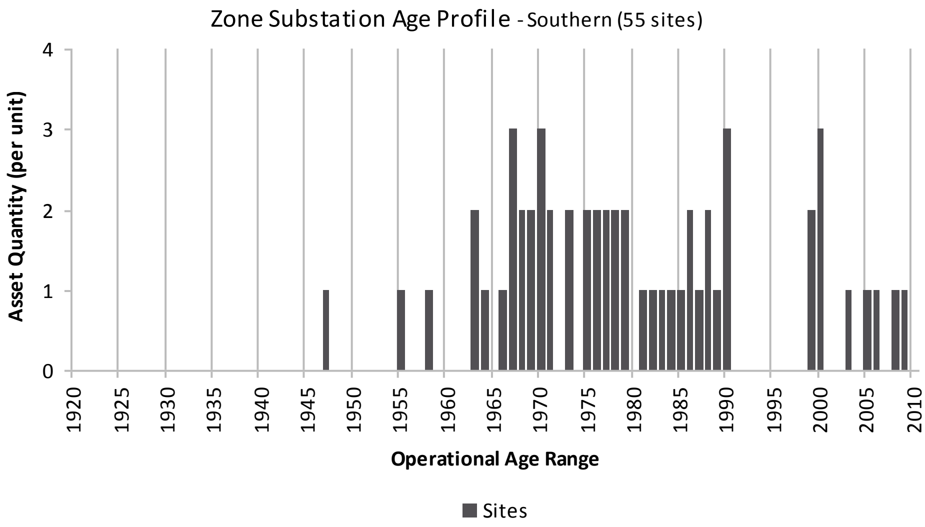


Figure 6-15 : Zone substation buildings age profile - Southern

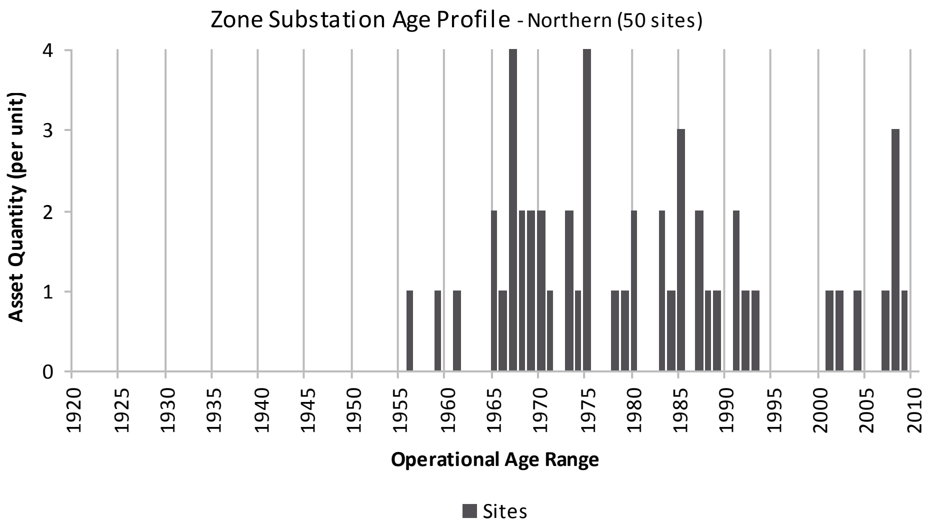


Figure 6-16 : Zone substation buildings age profile - Northern

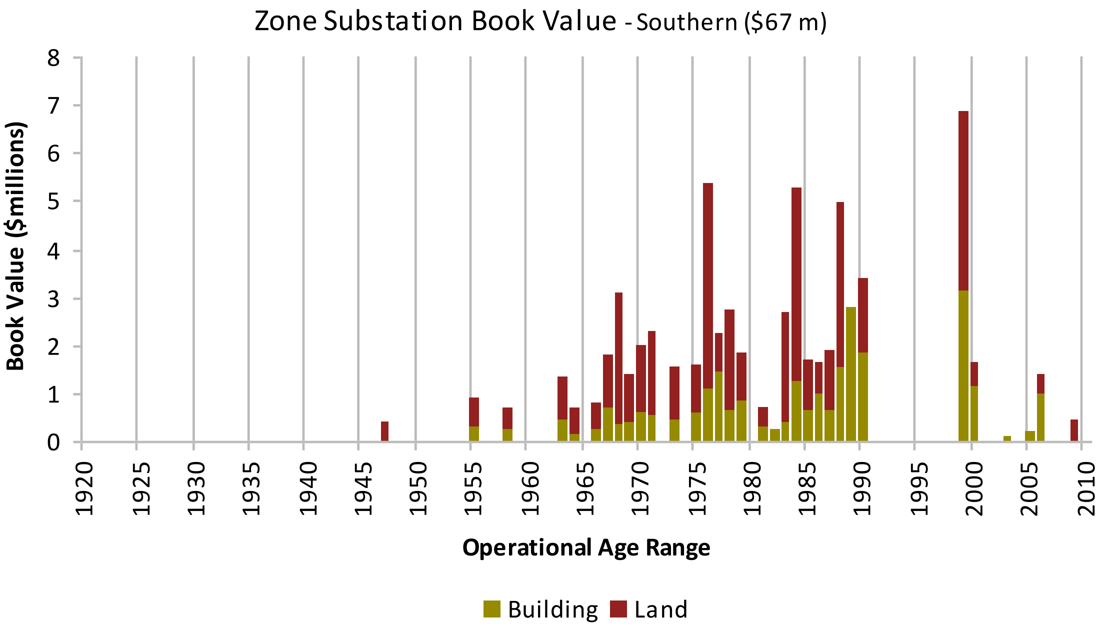


Figure 6-17 : Zone substation buildings book value – Southern

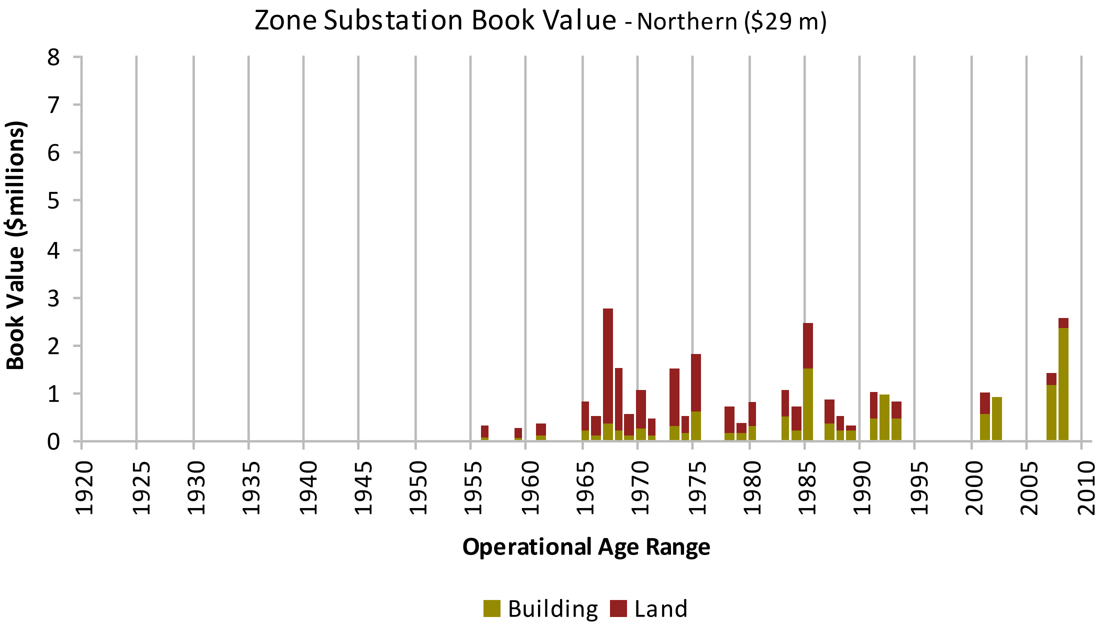


Figure 6-18 : Zone substation buildings book value – Northern

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 and window frames and rusting 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 & 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;
    - 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;
    - 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, empty and remove rubbish, structural integrity and cleanliness of internal walls, doors and windows, all drains and plumbing, sump pumps and alarms 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; 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 FY2011. It is anticipated that this will result in a refurbishment programme commencing in the 2012 financial year. The survey work will also include seismic evaluations of all zone substations.

New local authority seismic compliance rules in the Building Act 2004 are presently being evaluated. They may result in significant cost to Vector if it is required to bring existing substations up to the new compliance standards.

Vector continues to engage with local authorities on the building and seismic compliance requirements for existing zone substations.

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 system provides supply to the substation's 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 6-19 below.

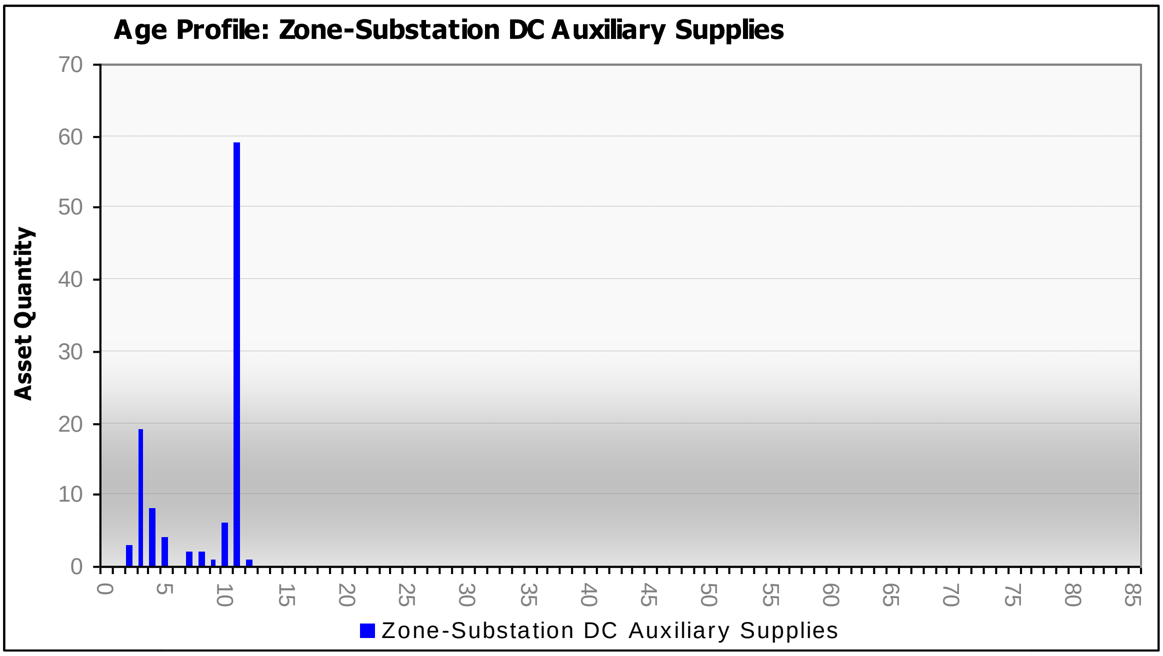


Figure 6-19 : Zone substation DC supplies – age profile

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, by ensuring that battery systems continue to have the capacity to operate equipment during a supply outage and to enable restoration of that loss of supply once any contingency has been rectified.

Vector is in the process of 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 6-20 below, is an example of remote on-line monitoring capabilities of a recently installed DC auxiliary system in a distribution substation.

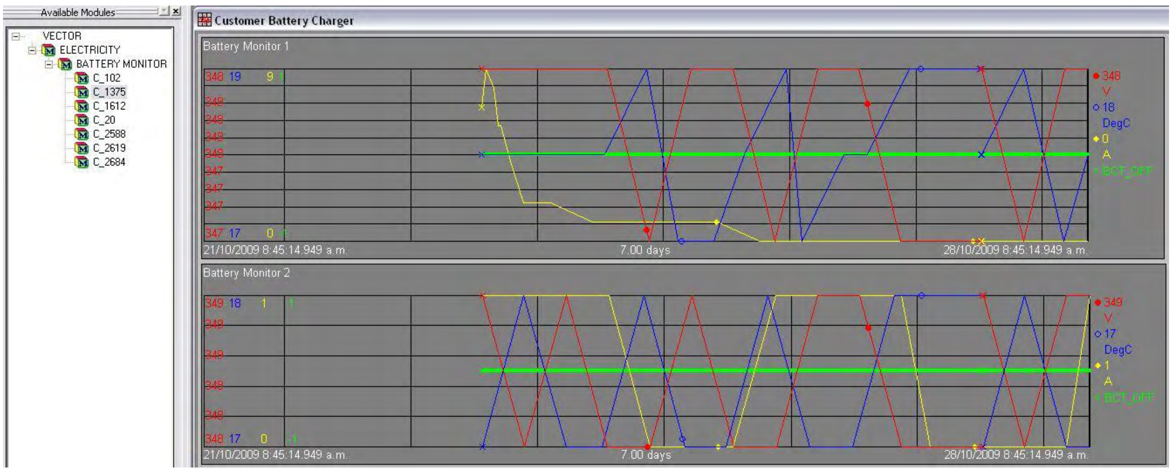


Figure 6-20 : Station batteries remote on-line monitoring

To address the issues listed above that Vector faces with its DC and auxiliary supplies, a systematic replacement programme has begun. This programme is illustrated in Figure 6-21.

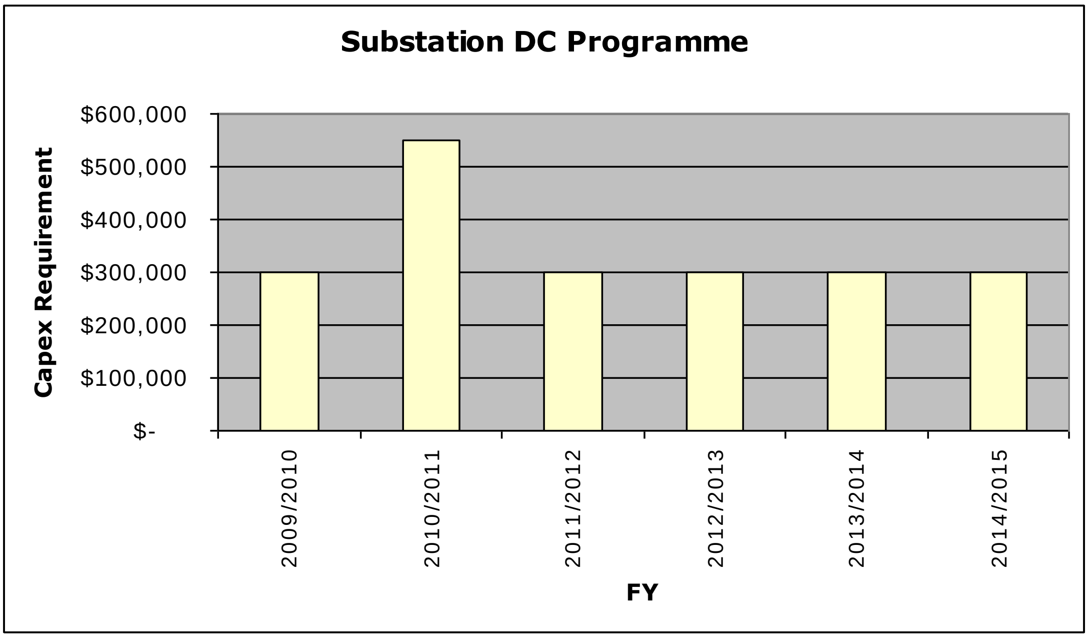


Figure 6-21 : DC auxiliary system replacement programme

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
- Electromechanical: 32 years

Vector's protection relay asset consists of 2600 main protection relays. The age and technology distribution is given in Figure 6-22 and Figure 6-23.

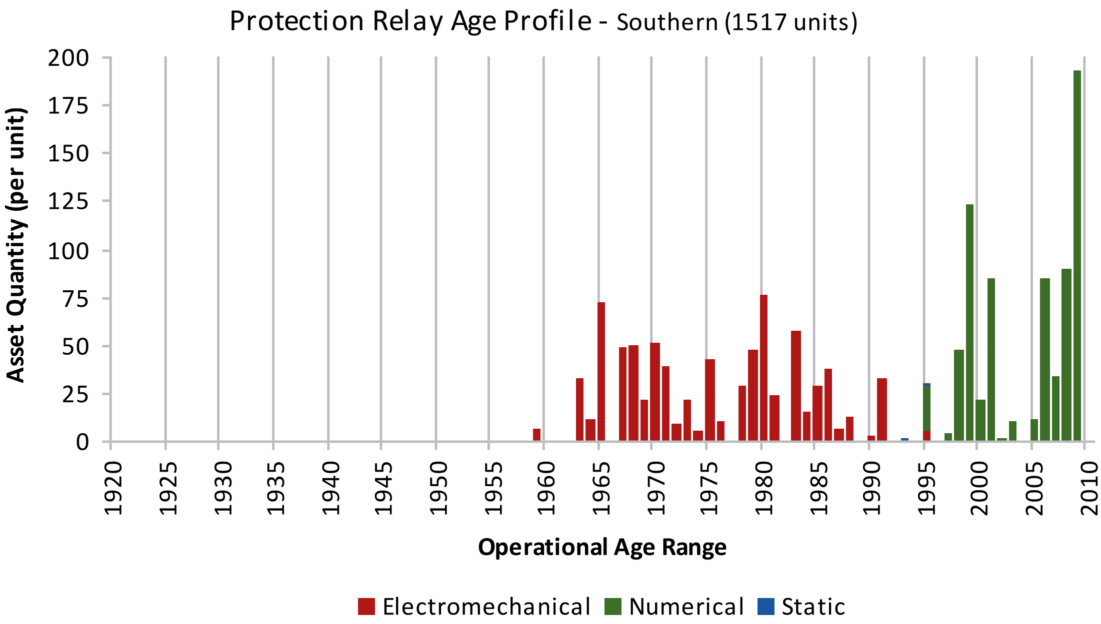


Figure 6-22 : Protection relay age profile – Southern

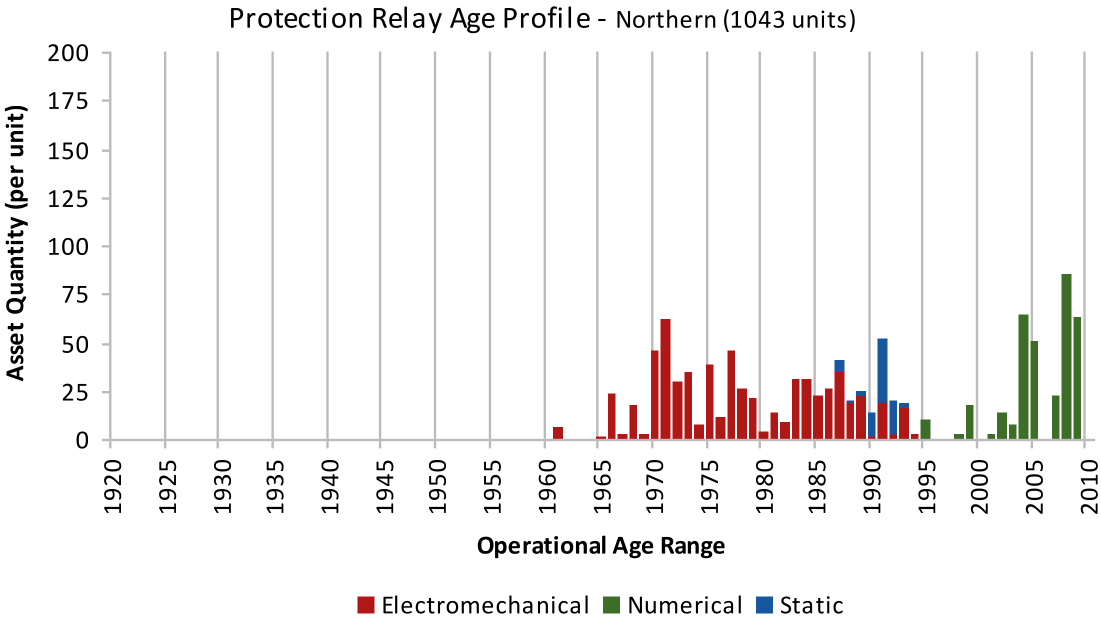


Figure 6-23 : Protection relay age profile – Northern

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 that it protects. Based on the cost of recently installed projects, the protection asset book value is estimated to be around $50 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 6-11 .

If the next (eight-yearly) testing occurs after the relay has been in service for ten years, the battery will be replaced at ten years. (Battery life is estimated to be ten years).

	Numerical Self Monitoring		Digital Non-Self Monitoring		Analogue (electro-mechanical or non-numerical electronic)		Measuring/Trip Circuit	AUFLS	IED Battery Replacement
	Minor	Major	Minor	Major	Minor	Major	-	-	-
Grid Interface	-	8	-	4	-	2	4	4*	8**
Other Stations	-	8	-	4	-	6	4/6/8***	4/6/8****	8**
Trf. Mech. Protn.	***								-
Transformer IED	***								8**
Transformer Voltage Regulating Relay, OTI and WTI	***								

Notes:

(1) Differential protection between the grid and a connected asset to be treated a single protection function and be tested both ends.

(2) The testing interval shall be based on the main protection in cases where more than one device is installed. For example (at grid interface).

(3) HHTA Translay and 7SJ632 OCEF: Interval = two yearly.

(4) 7SD610 and CDG OCEF: Interval = eight yearly.

[yellow] Required by Electricity Governance Rules.

* Required, but might be able to extend to eight years for digital self-monitoring relays with UFLS incorporated.

** Refer to note (3).

*** Align with associated protection relay (e.g. buchholz) maintenance interval.

**** Dependent on type of relay (digital self-monitoring, digital non-self-monitoring, analogue).

Table 6-11 : Protection relay maintenance frequencies

6.3.6.2 Replacement Programme

The basic aim of the protection equipment replacement strategy is to ensure that 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. It also needs to consider lifecycle management factors and must ensure that full protection of our switchgear and transformers is 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 that 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. Table 6-12 below summarises the anticipated protection replacement capital expenditure (capex) for both regions.

Southern	**2010**	**2011**	**2012**	**2013**	**2014**
Discrete Replace	$1.24m	$1.70m	$1.37m	$0.95m	$1.28m
Combine Replace	$1.23m	$0.80m	$0.33m	$0.00m	$0.00m
Total	$2.5m	$2.5m	$1.7m	$0.9m	$1.3m
Northern	**2010**	**2011**	**2012**	**2013**	**2014**
Discrete Replace	$0.76m	$0.43m	$0.87m	$0.41m	$0.51m
Combine Replace	$0.26m	$0.38m	$0.00m	$0.34m	$0.00m
Total	$1.0m	$0.8m	$0.9m	$0.8m	$0.5m

Table 6-12 : Protection relay replacement programme - expenditure estimate

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 is under way 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 our network 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 40 Plessey GPT RTUs and Siemens PCC systems to be replaced in the coming years.

  In the Northern region 33 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 to 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.

An overview of Vector's load control systems (pilot and ripple based), with their associated age profiles, is given in Table 6-13 and Table 6-14 .

Network Area	Site	Manufacturer	Type	Frequency (Hz)	Power Rating (kVA)	Age (Years)	Protocol	Injection Bus (kV)	Duty Cycle (Telegram/h)
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	-
	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	-
Network Area	Site	Manufacturer	Type	Frequency (Hz)	Power Rating (kVA)	Age (Years)	Protocol	Injection Bus (kV)	Duty Cycle (Telegram/h)
	Forest Hill	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Milford	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
	Orewa	-	Pilot Wire	-	-	>50	Pilot Wire	11	-
(Henderson GXP)	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 GXP)	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	-
	Waikaukau Rd	-	Pilot Wire	-	-	>50	Pilot Wire	11	-

Table 6-13 : Asset age profile - Northern region – pilot wire system

Network	Type	Year of Manufacturer	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
Southern	Static	1997	1
Southern	Static	1999	1
Southern	Static	2002	1
Southern	Static	2005	1
Southern	Static	2006	1
Total (units)			**30**

Table 6-14 : Ripple load control population

It is recognised that 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. As such, Vector's intention is to maintain these during the transitional phase.

6.3.9 Sub-transmission and Distribution Overhead Network

The overhead line system consists of 26km of 110kV line, 357km of 33kV line, 2.9km of 22kV (linked to the adjacent Counties Power network), 3,632km of 11kV line and 3,771km of 400V line. Vector also has 24km of 6.6kV line in service on the Southern region, but this is being progressively uprated to 11kV.

Around 115,000 poles support the overhead distribution network, of which 11% are wood and the rest concrete. There are also steel towers in the Northern region primarily supporting 110kV and 33kV circuits.

New poles are all concrete with the exception of road crossing service poles which are CCA treated softwood. 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[34].

Through Vector's ongoing surveys, inspection and test programmes as per ENS-0188, it is anticipated that this data will be corrected over time.

The number of poles in each area is summarised in Table 6-15 below.

Concrete	HV	MV	LV	SL
Southern		22223	23031	214
Northern	68	46961	13829	753
Total	**68**	**69184**	**36860**	**967**
Steel	HV	MV	LV	SL
Southern	0	0	27	172
Northern	62	76	38	292
Total	**62**	**76**	**65**	**464**
Wooden	HV	MV	LV	SL
Southern		2149	4167	70
Northern	76	1328	1556	52
Total	**76**	**3477**	**5723**	**122**
Population	HV	MV	LV	SL
Southern	0	24372	27225	456
Northern	206	48365	15423	1097
Total	**206**	**72737**	**42648**	**1553**

Table 6-15 : Overhead structures – population by material type

The Vector GIS also shows 285 streetlight poles in the Southern region and 805 in the Northern region. These streetlights are possibly owned by local councils and may have been incorrectly assigned to Vector. Investigations are being carried out to clarify the ownership of these poles.

[34] This includes the fact that for the ODV valuation methodology, poles are not separately recorded.

The age profiles of the wooden and concrete poles on the Vector network is presented in Figure 6-24, Figure 6-25, Figure 6-26 and Figure 6-27.

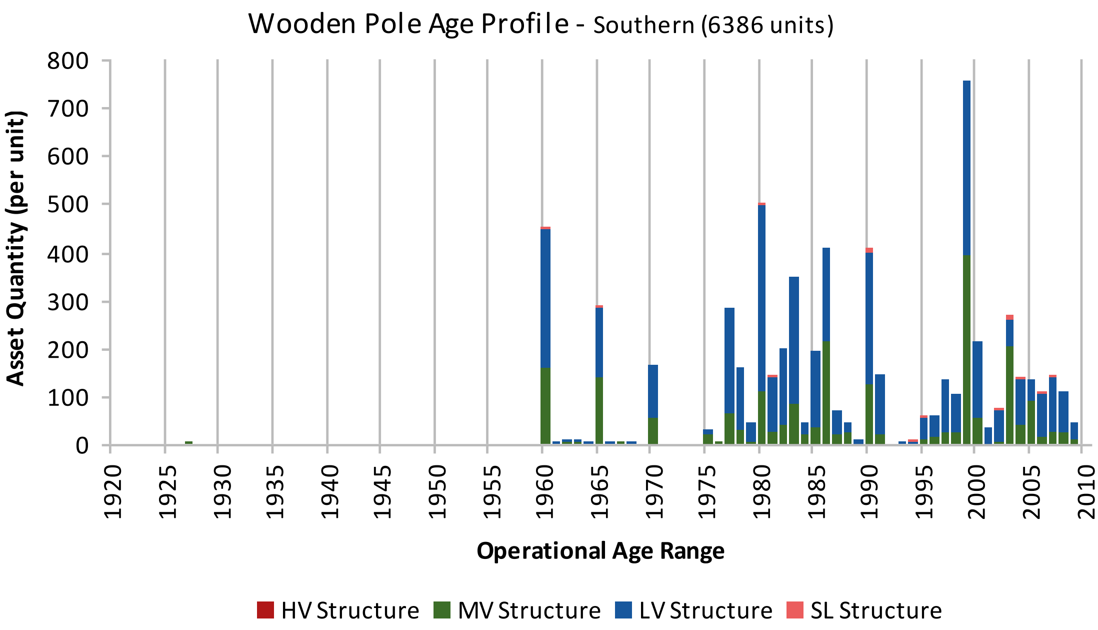


Figure 6-24 : Wooden pole age profile – Southern

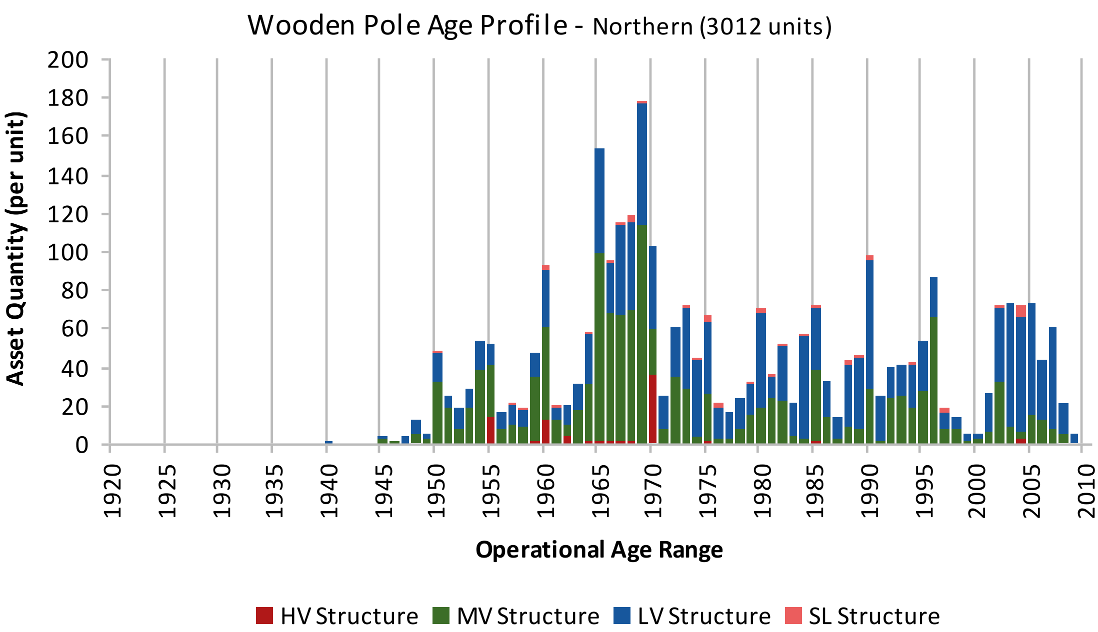


Figure 6-25 : Wooden pole age profile – Northern

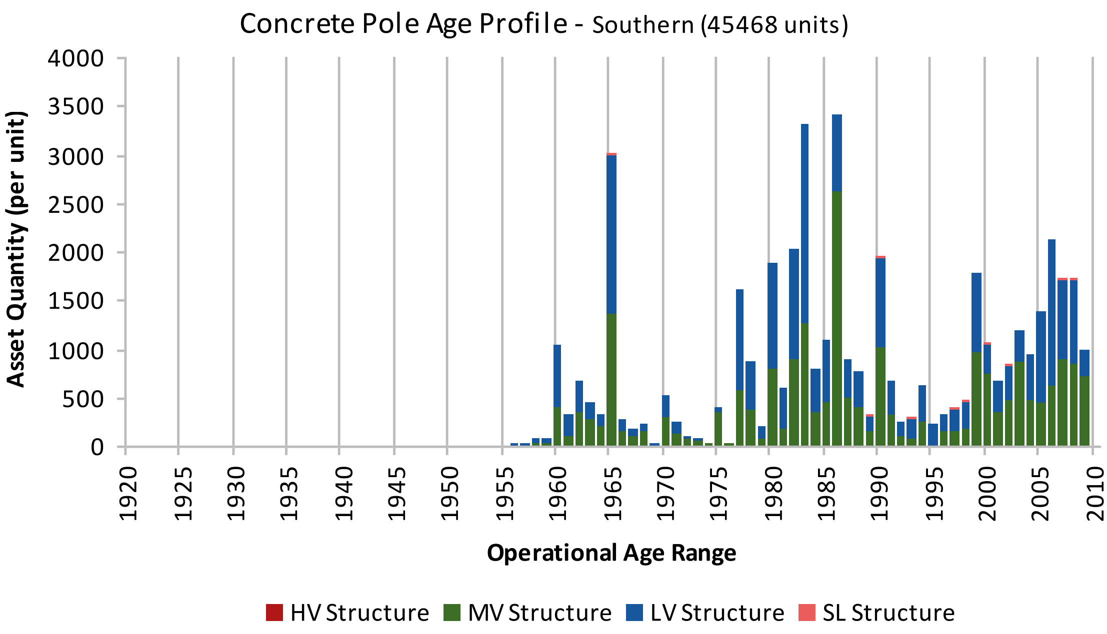


Figure 6-26 : Concrete pole age profile – Southern

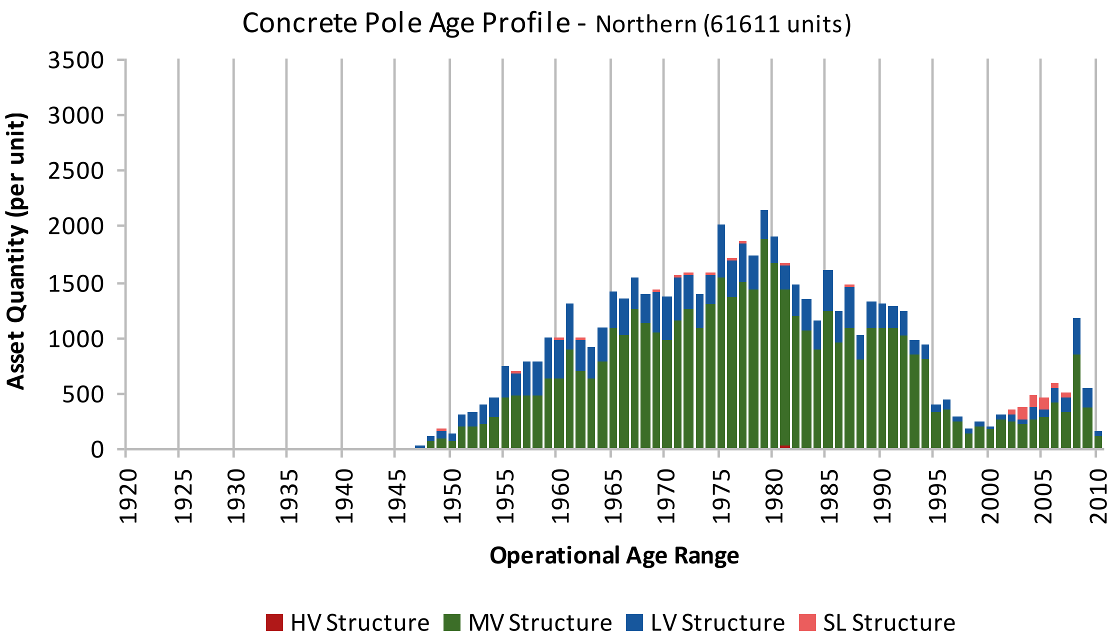


Figure 6-27 : Concrete pole age profile – Northern

There are 108 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 over the past few years.

Based on the Vector GIS records, the total value of the wood, steel and concrete poles in the Southern region is $320 million and in the Northern region is $402.9 million. Due to legacy/historical data issues, detailed replacement cost profiles cannot be prepared at this stage. Following Vector's current programme to update our historical asset performance information, this situation is expected to improve[35].

It should be noted that 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.

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 five 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 strength 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 which are assessed by other means.

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, LV fuses, 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 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 that is likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.9.2 Maintenance, Refurbishment and Replacement Programmes

Poles identified as problematic during the annual inspection or test programme may be repaired on site or replaced, depending upon their condition. Poles inspected requiring attention are tagged according to their as-found condition in accordance with Vector inspection and replacement Electricity Standard ENS-0057.

[35] Recognising however that records for some of the older assets will remain unavailable.

- Blue Tag

  Overhead line structures that are 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 that are 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 must be repaired or replaced not later than three months after the discovery of the risk of failure.

- Yellow Tag

  Overhead line structures that are found to be incapable of supporting design loads must be marked with a yellow tag, and must be repaired or replaced within 12 months of finding of the incapability.

6.3.10 Overhead Conductors

Conductor types and sizes on the Vector network vary across the overhead network and are predominantly Cu, all aluminium conductors (AAC) or aluminium conductor steel reinforced (ACSR) conductors. A smaller quantity of all aluminium alloy conductors (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 conductors (HVABC) which was installed about 15 years ago. Although the material proved to be effective for improving reliability, due to high installation costs it was not continued. Table 6-16 below shows the amount of overhead conductor in kilometres (km) by operating voltage region, as well as the associated current book-value.

Figure 6-28 and Figure 6-29 show the age profile for the MV and HV conductors by region. The low voltage (LV) conductor profiles are provided in Figure 6-30 and Figure 6-31.

Population	110kV	33kV	22kV	11kV	6.6kV	400V
Southern	0km	46km	3km	871km	24km	1693km
Northern	26km	316km	0km	2938km	0	2066km
TOTAL	**26km**	**362km**	**3km**	**3809km**	**24km**	**3759km**

Book Value	110kV	33kV	22kV	11kV	6.6kV	400V
Southern	$0.0m	$3.4m	$0.1m	$31.7m	$0.9m	$39.8m
Northern	$2.4m	$13.2m	$0.0m	$56.1m	$0.0m	$27.6m
TOTAL	**$2.4m**	**$16.5m**	**$0.1m**	**$87.8m**	**$0.9m**	**$67.4m**

Table 6-16 : MV and HV conductor - population and book value

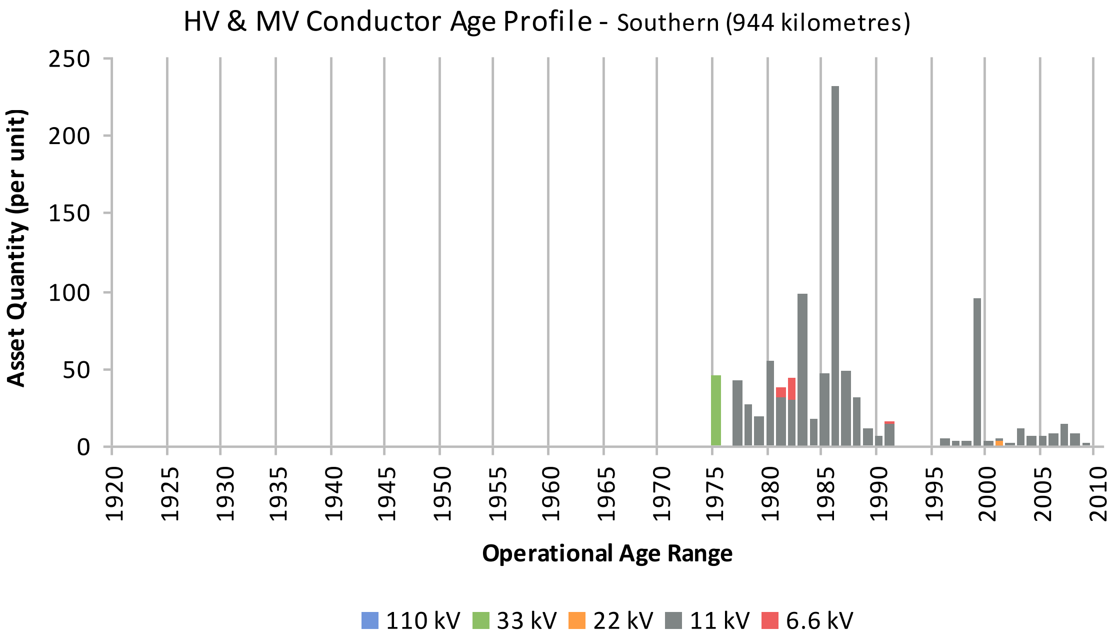


Figure 6-28 : HV and MV conductor age profile – Southern

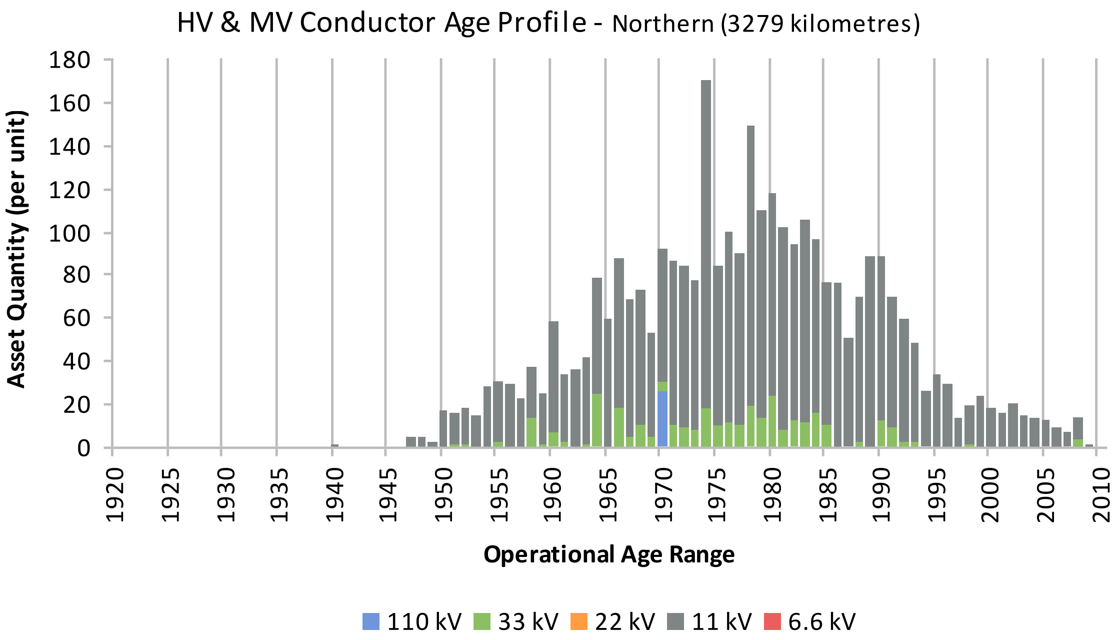


Figure 6-29 : HV and MV conductor age profile – Northern

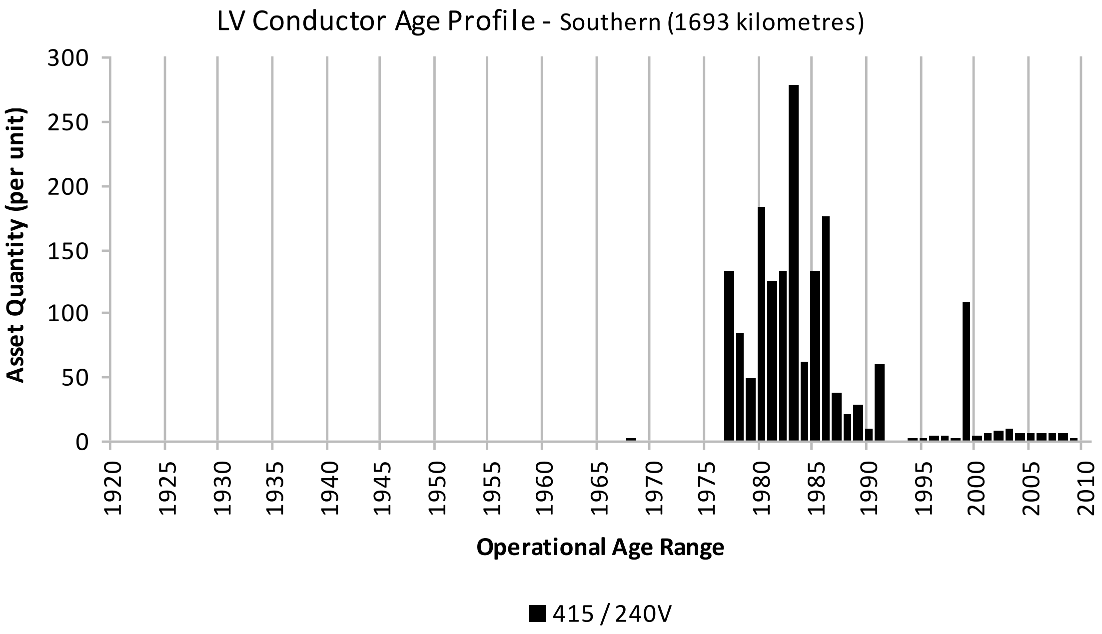


Figure 6-30 : LV conductor age profile – Southern

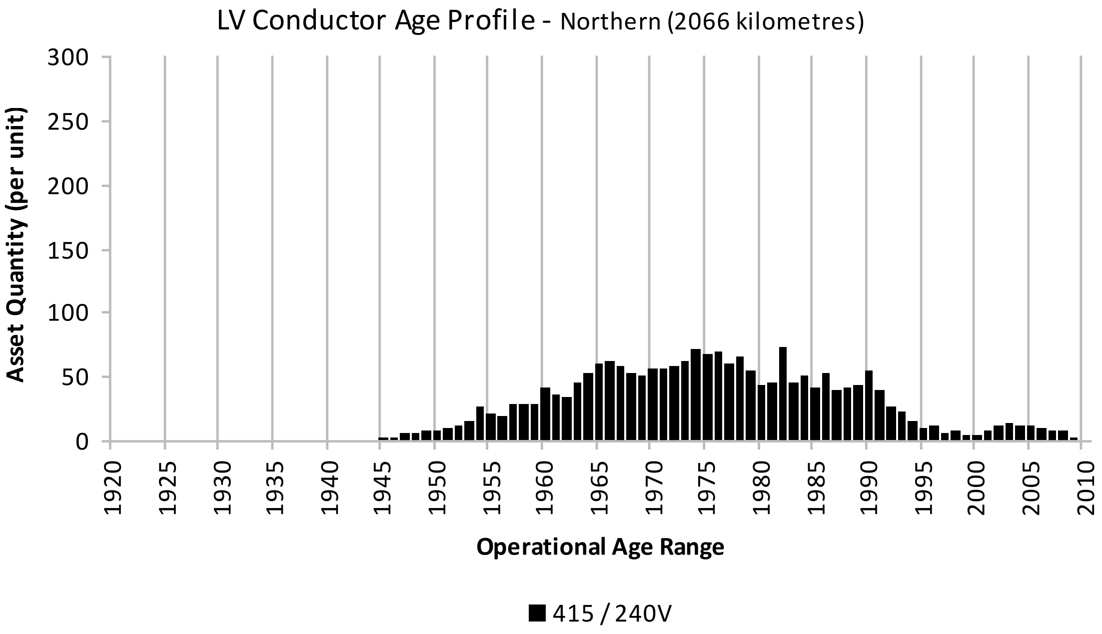


Figure 6-31 : LV conductor age profile - Northern

In Figure 6-32 to Figure 6-35 the book-values for the HV, MV and LV line conductors are set out for each region.

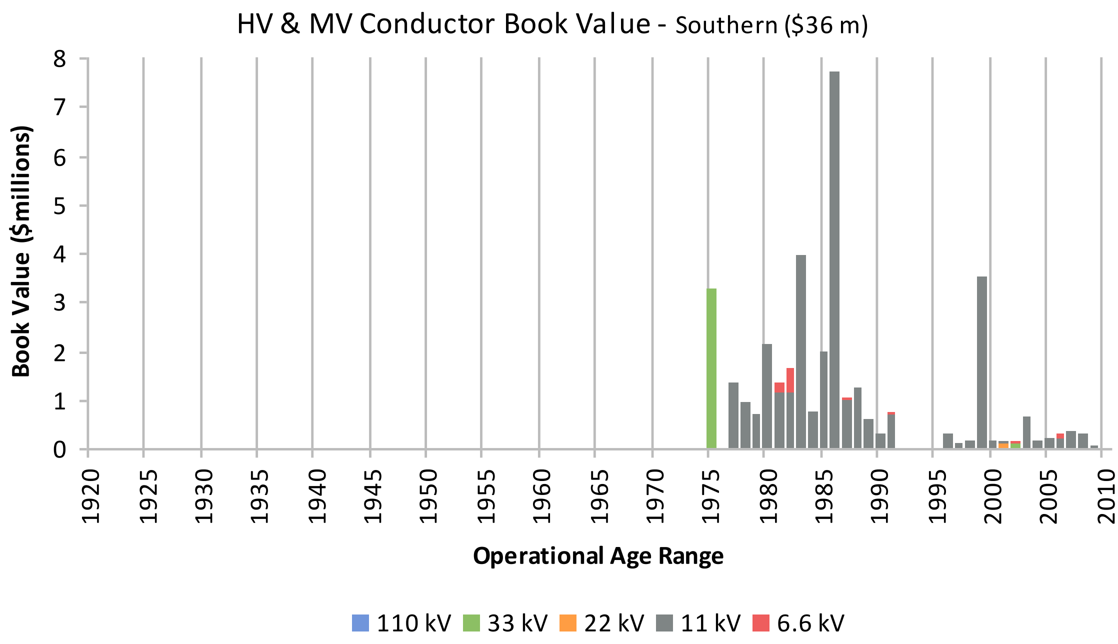


Figure 6-32 : HV and MV conductor book value – Southern

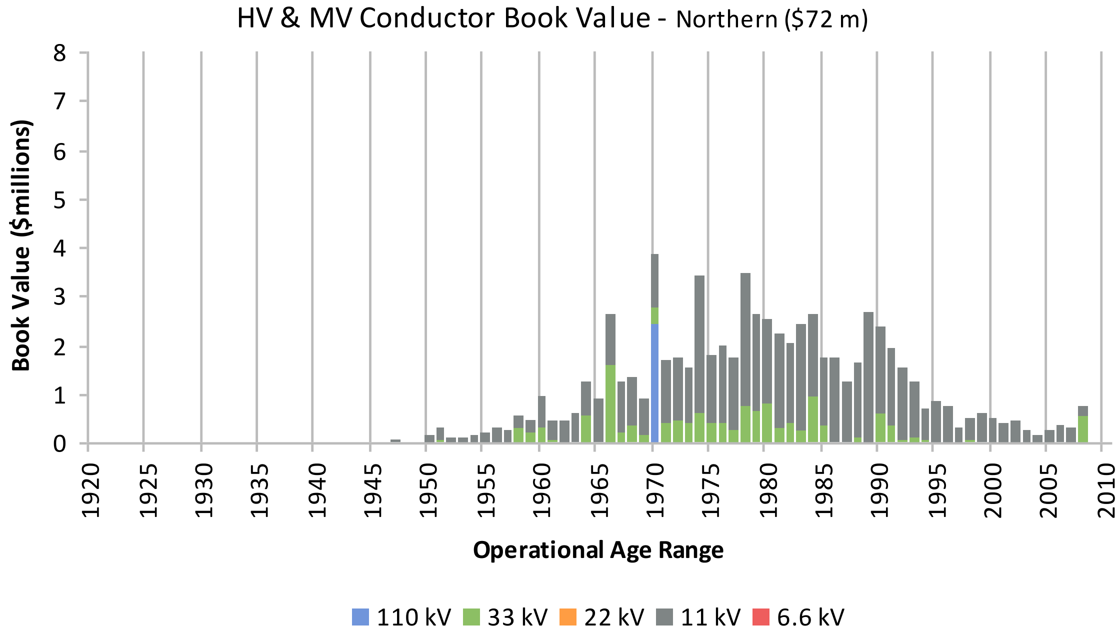


Figure 6-33 : HV and MV conductor book value - Northern

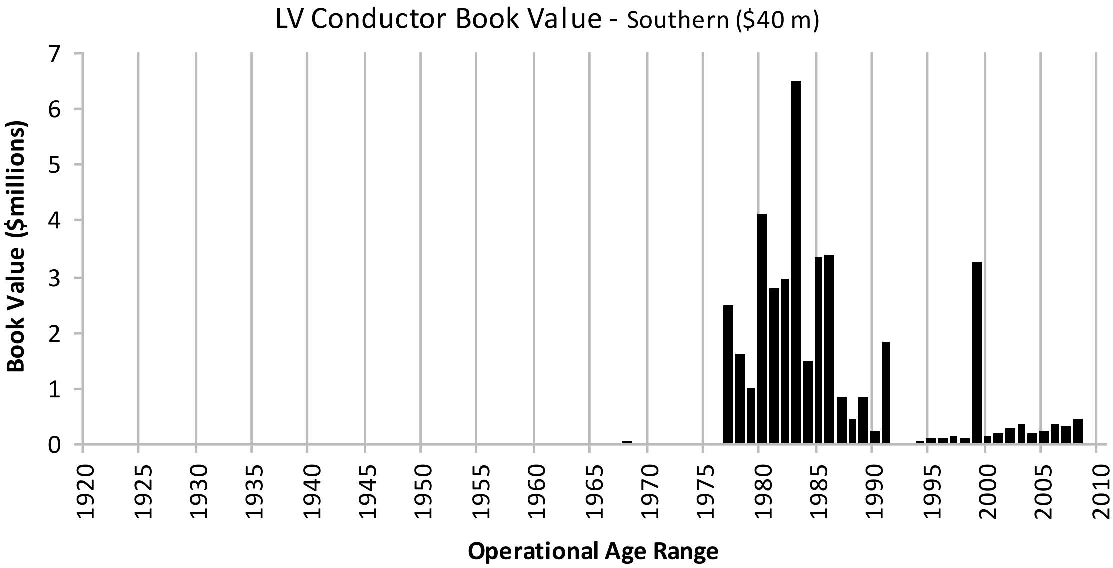


Figure 6-34 : LV conductor book value – Southern

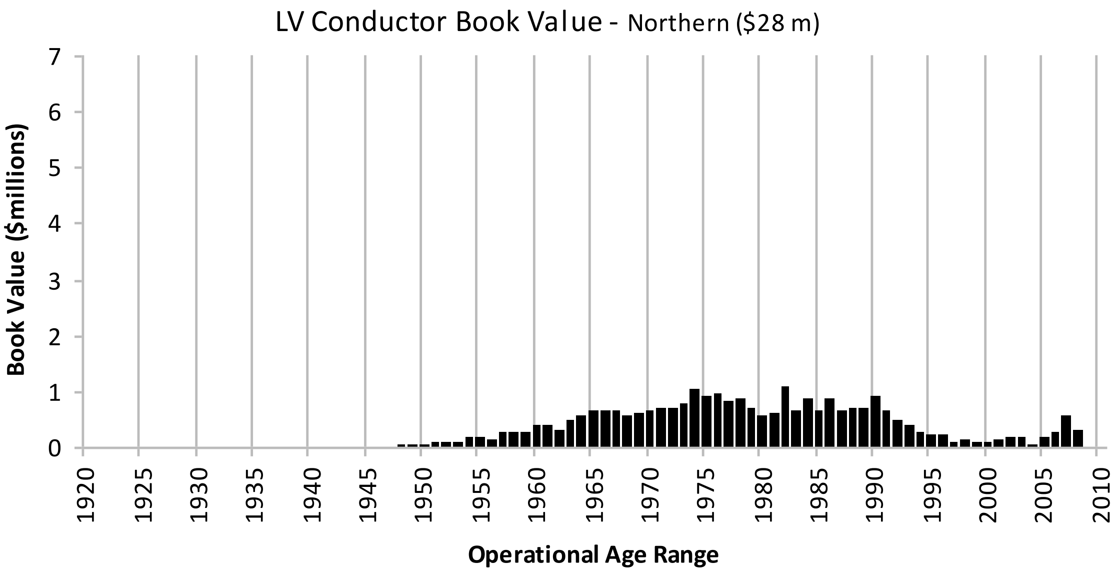


Figure 6-35 : LV conductor book value - Northern

The condition of the aluminium conductors and most Cu conductors is good. However there are areas reticulated with small-sized Cu conductors which have reached the end of their life. Vector is unwilling to even use wedge taps on these conductors because of the damage they are likely to cause to the corroded annealed Cu. Vector has a replacement programme underway to address this issue. There are no other systemic issues.

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 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, LV fuses, 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 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; and
- Fault and emergency maintenance:
  - Any identified defect that is likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.10.2 Maintenance and Refurbishment Programme

Conductors are repaired or replaced when they fail in line with industry practice.

Conductors are not refurbished but recovered conductors in good condition may be reused.

6.3.11 Overhead Switches

Overhead switches include MV 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 6-17 shows the population and book value of overhead switches on the Vector network. "Air break switches" includes isolating links.

Population	Air Break	Recloser	Gas Break	Sectionaliser
Southern	407	27	167	14
Northern	650	100	245	35
TOTAL	**1057**	**127**	**412**	**49**
Book Value	**22kV**	**11kV**	**6.6kV**	**400V**
Southern	$1.4m	$1.9m	$3.3m	$0.5m
Northern	$0.9m	$2.9m	$4.3m	$0.9m
TOTAL	**$2.3m**	**$4.9m**	**$7.5m**	**$1.4m**

Table 6-17 : Overhead switchgear - population and book value

Age profiles for 11kV and 33kV air break 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 new enclosed switch installations have been triggered by Vector's policy to replace ABSs with an enclosed switch when the opportunity arises, rather than at end of life. This has meant that 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 6-36 and Figure 6-37 below clearly show the transition to enclosed switches in more recent times.

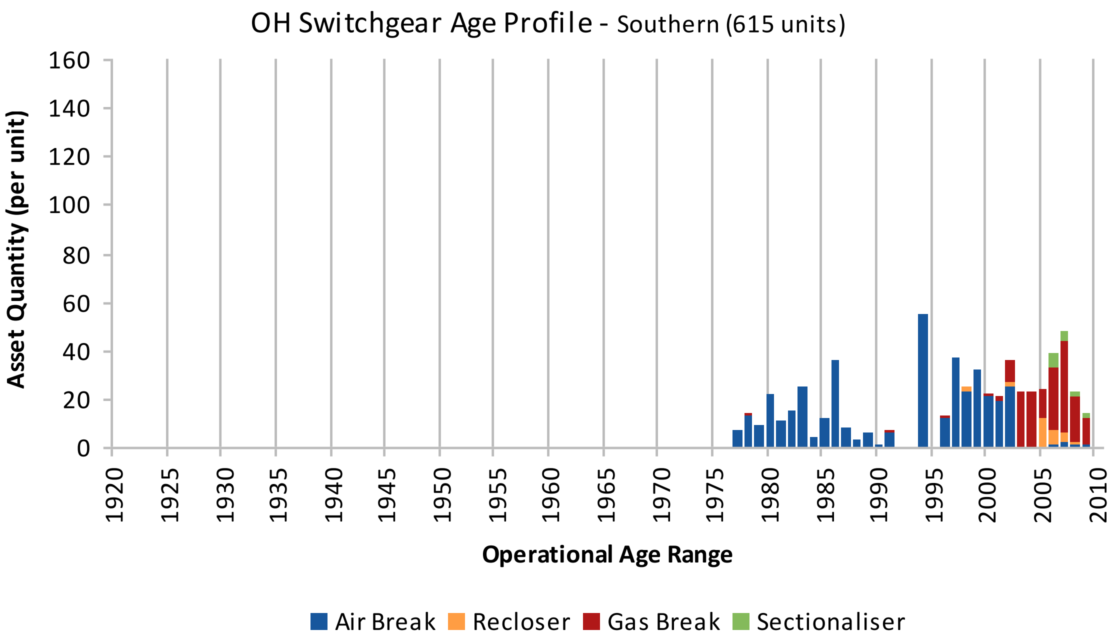


Figure 6-36 : Overhead switchgear age profile - Southern

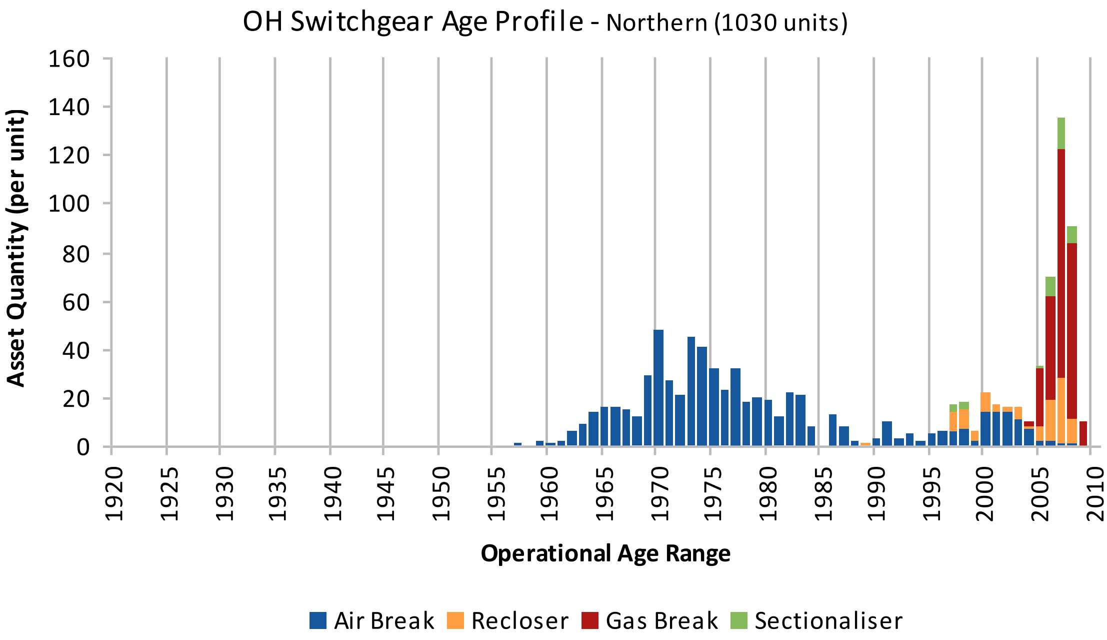


Figure 6-37 : Overhead switchgear age profile - Northern

The combined book-value of overhead switchgear assets on both networks is $16 million. Figure 6-38 and Figure 6-39 below show the value of overhead switchgear assets on each network.

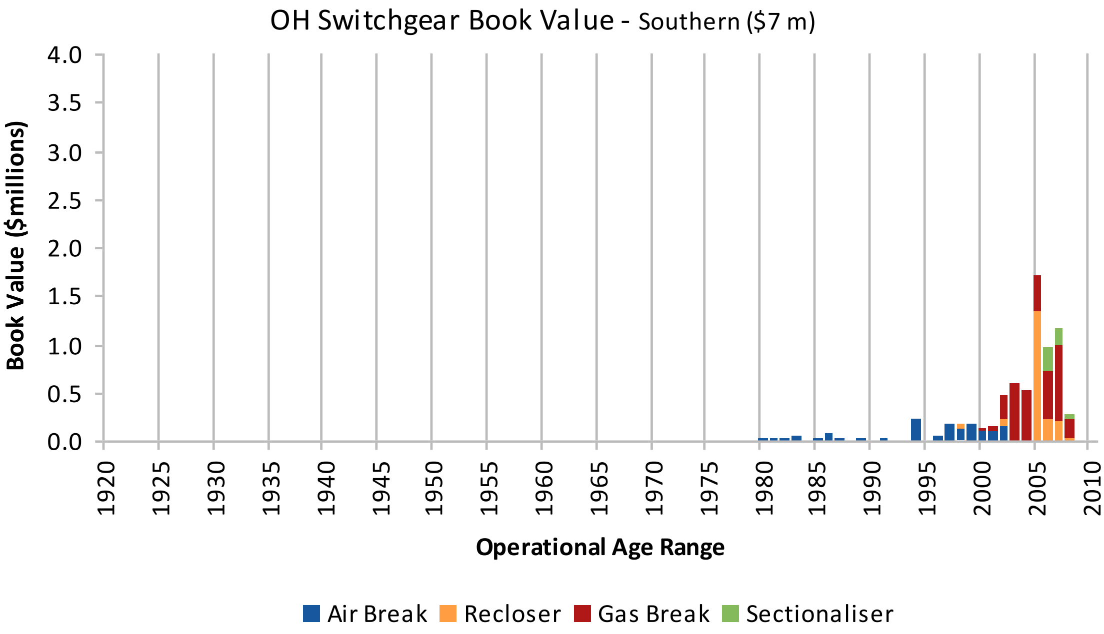


Figure 6-38 : Overhead switchgear book value - Southern

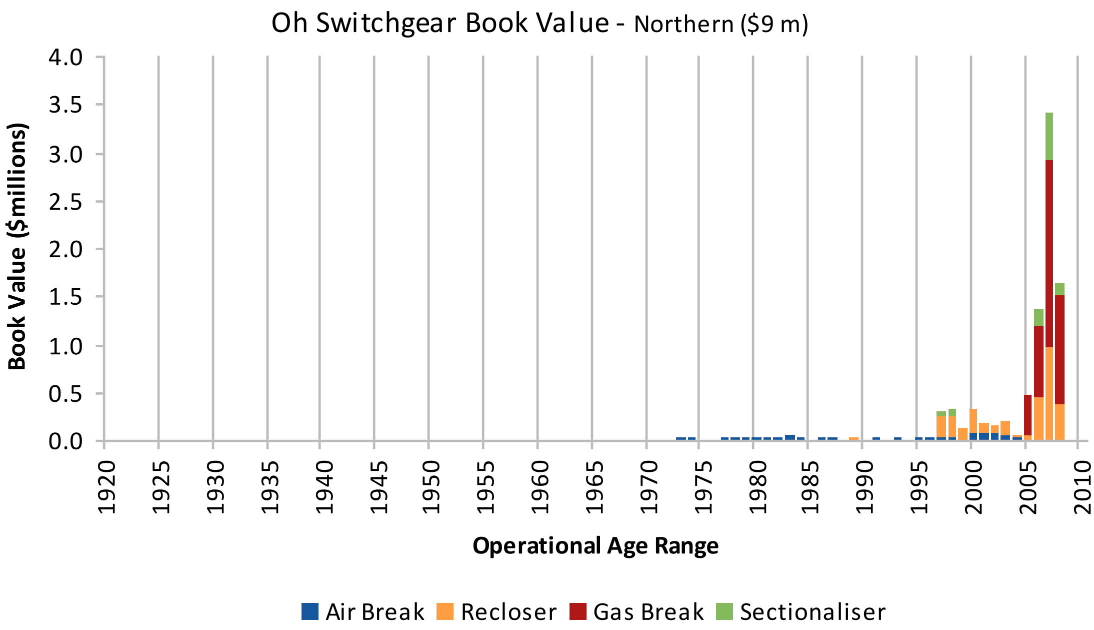


Figure 6-39 : Overhead switchgear book value - Southern

6.3.11.1 Asset Condition

Most of the ABS' are more than 20 years old and are in good to fair condition. The vast majority of the SF_6 switches are less than seven 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 ENS -0187 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, LV fuses, 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 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; and
- Fault and emergency maintenance:
    - Any identified defect that is likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

ABS' 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:
    - 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 compliant sites require step and touch voltage retesting using off-frequency injection current;
    - 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; 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 indentified MV ABS defect that meets the operating constraint criteria will require switch replacement if still essential, modern replacement being an enclosed SF6 switch;
    - An indentified 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; and
- Fault and Emergency Repair:
    - All indentified 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

ABS' are maintained when tested. The enclosed switches do not require maintenance.

ABS' are replaced by an enclosed switch if they have to be removed from the pole because of a defect. They are not refurbished. Enclosed switches are returned to the supplier.

There is no proactive replacement programme for switches. However, when cluster overhead replacement and pole replacements occur, any associated ABSs are replaced with gas switches.

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.

In general HV crossarms are in better condition than the 400V equivalents. It is anticipated that a detailed survey of the LV network will be carried out in 2010/11 and, if warranted, a programme to systematically refurbish/renew the network.

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 class three and, anecdotally, 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 class one or two 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 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, LV fuses, 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 an 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 that is 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

Defective crossarms found during the annual line patrols are replaced. Crossarms are not refurbished as it is not cost effective to do so.

6.3.13 Overhead Network - General

Various components of the overhead network are separately discussed above. In this section some general issues Vector has 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[36].

6.3.13.1 Connectors

Aluminium Ampact wedge taps installed to connect Cu jumpers to aluminium conductors have been found to be corroding badly after about two years of service. These connectors were specifically selected based on the manufacturer's advice that they were suitable for a bimetal (Cu to aluminium connections) application. So far the problem has only been found in exposed coastal areas, but investigations on the rest of the network are continuing.

For all new bimetal applications, the aluminium wedge connectors are now encased in a gel box to keep moisture away from the joint.

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.

[36] 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).

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.

6.3.14 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 6.6kV and the older 11kV cables are PILC or paper insulated aluminium sheath (PIAS) construction, with the more recent 11kV and the 22kV cables having XLPE insulation. Table 6-18 below shows the breakdown of distribution cables by voltage class, network and book value.

Population	22kV	11kV	6.6kV	400V
Southern	25km	1935km	42km	2985km
Northern	-	1199km	-	1798km
TOTAL	**25km**	**3134km**	**42km**	**4783km**

Book Value	22kV	11kV	6.6kV	400V
Southern	$12.0m	$261.1m	$5.6m	$166.6m
Northern	$0.0m	$99.5m	$0.0m	$66.9m
TOTAL	**$12.0m**	**$360.7m**	**$5.6m**	**$233.5m**

Note: Quantities exclude pole riser lengths of 8m per LV termination, 9m per 6.6kV, 11kV and 22kV termination, and 10m per 33kV termination

Table 6-18 : 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 6-40 to Figure 6-47.

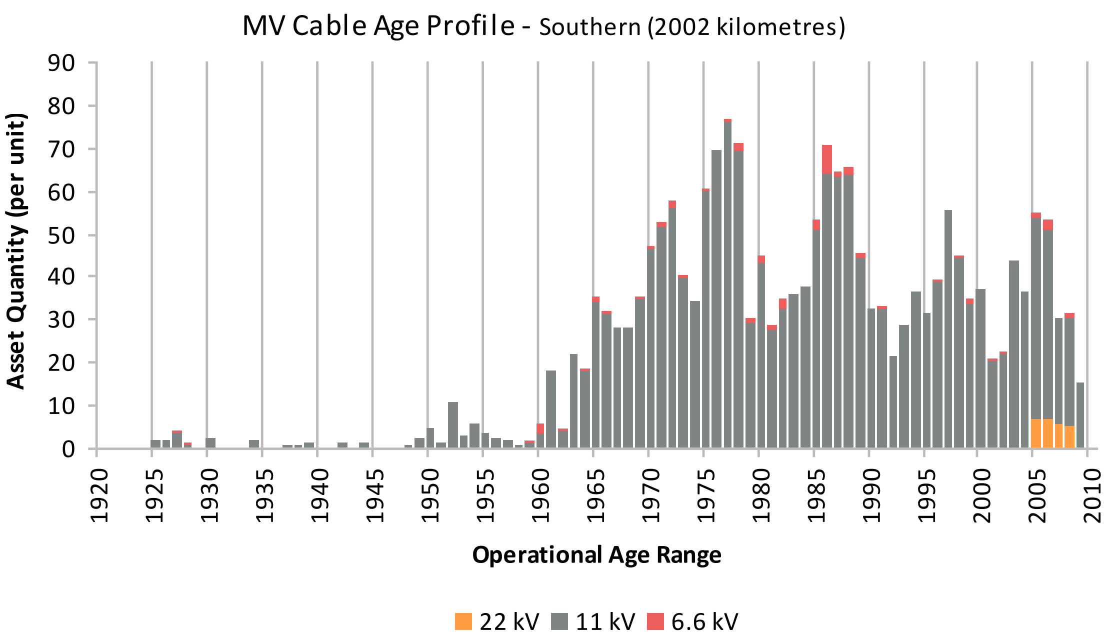


Figure 6-40 : MV cable age profile – Southern

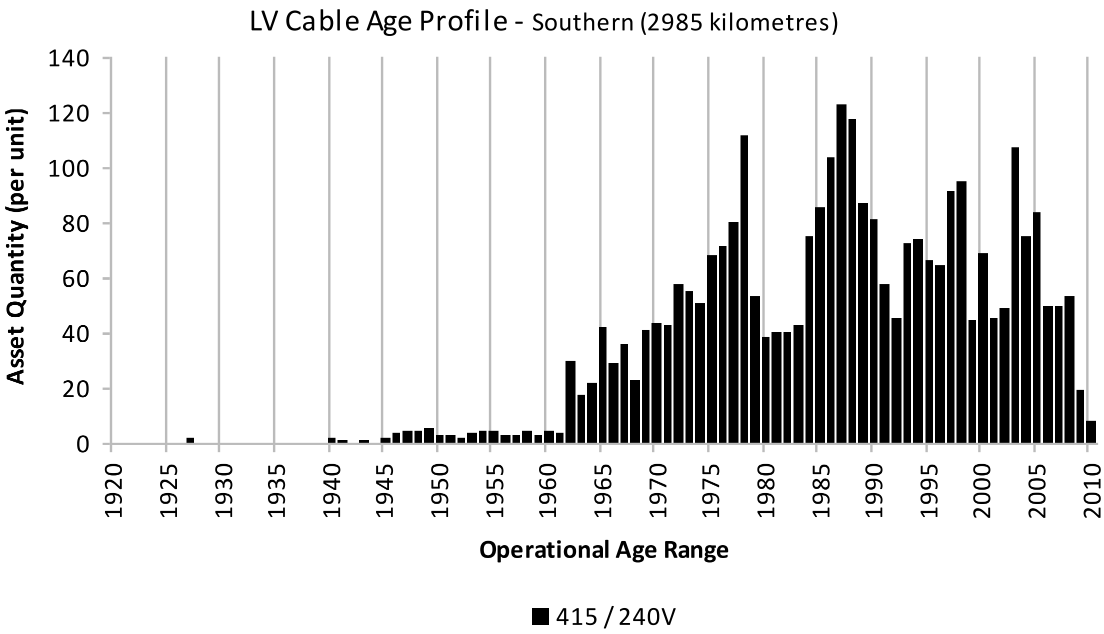


Figure 6-41 : LV cable age profile – Southern

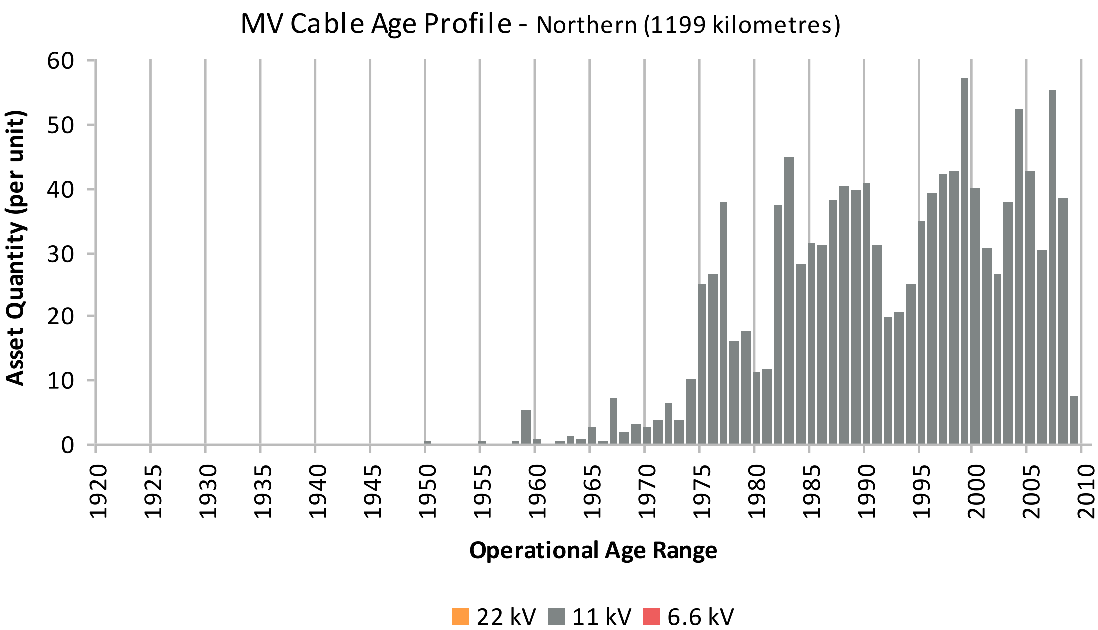


Figure 6-42 : MV cable age profile – Northern

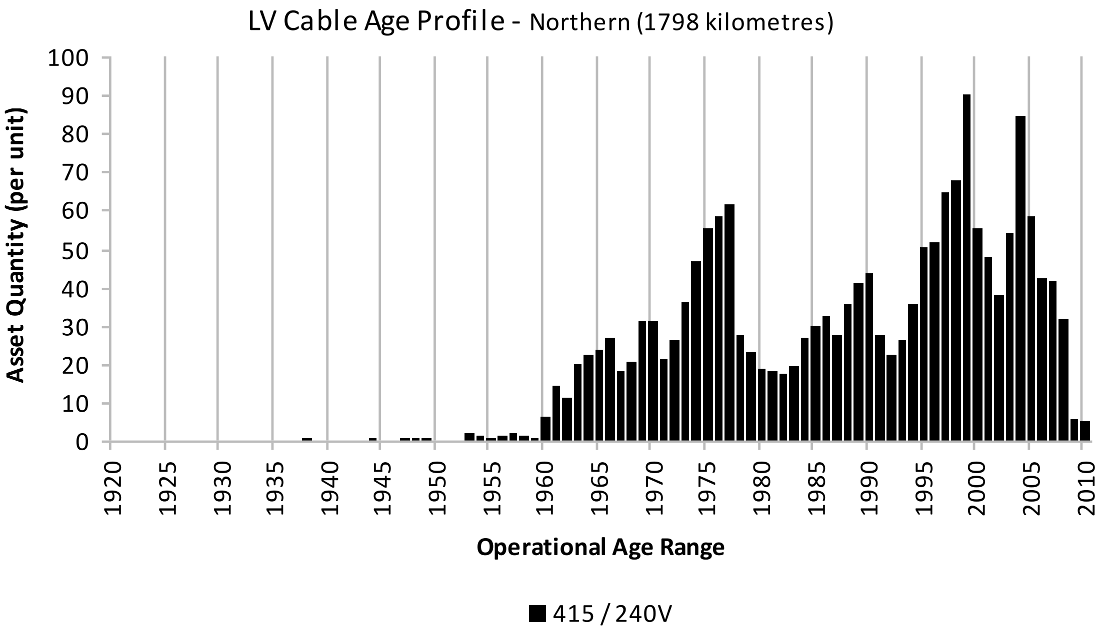


Figure 6-43 : LV cable age profile – Northern

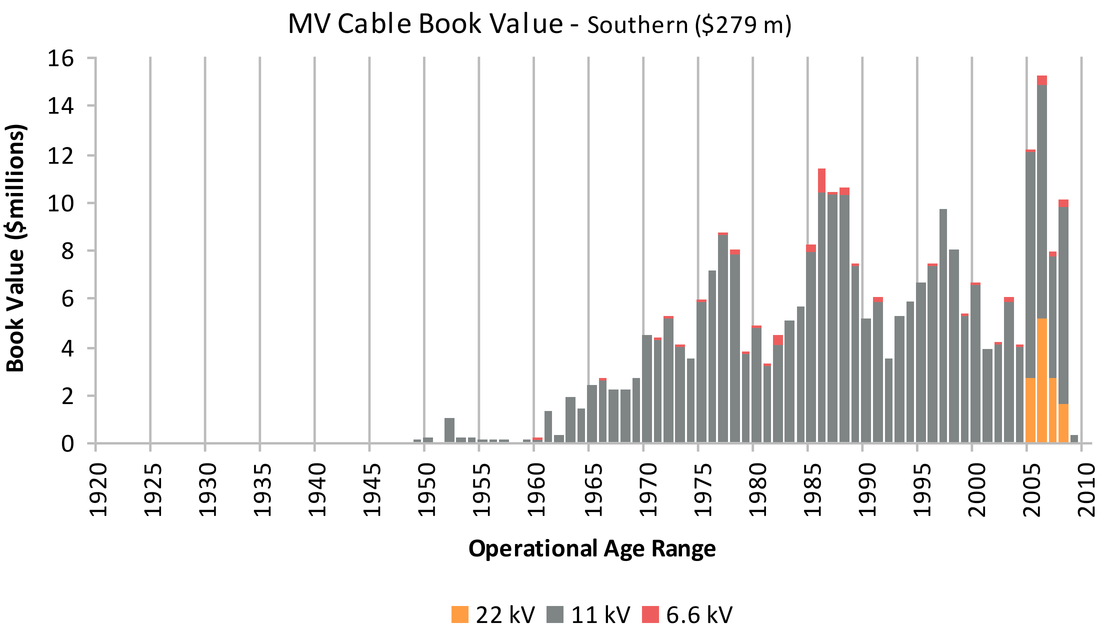


Figure 6-44 : MV cable book value – Southern

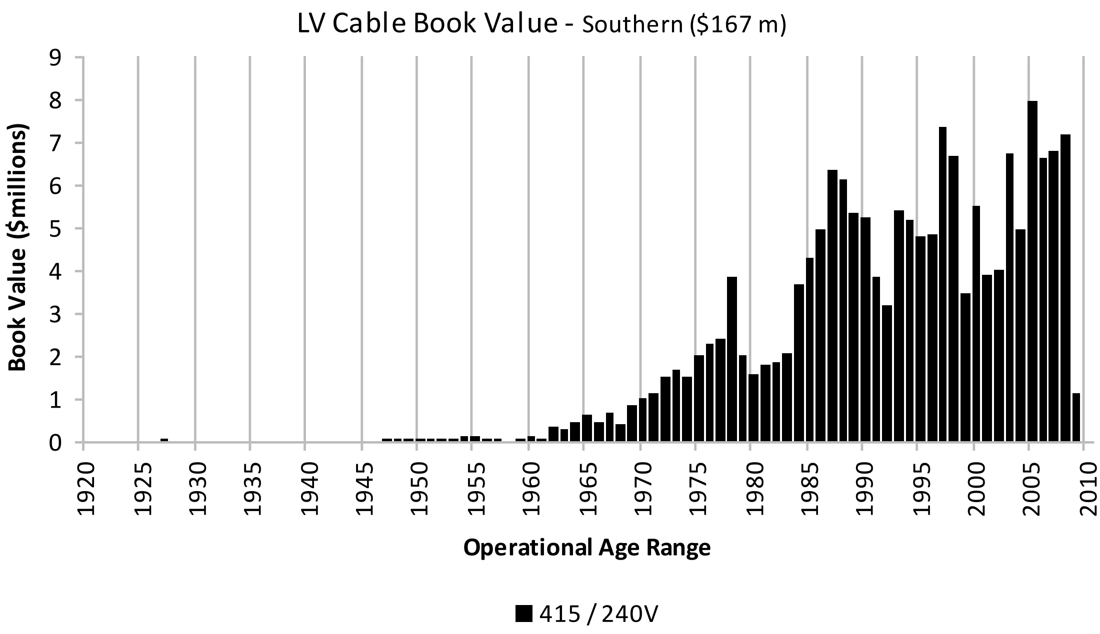


Figure 6-45 : LV cable book value – Southern

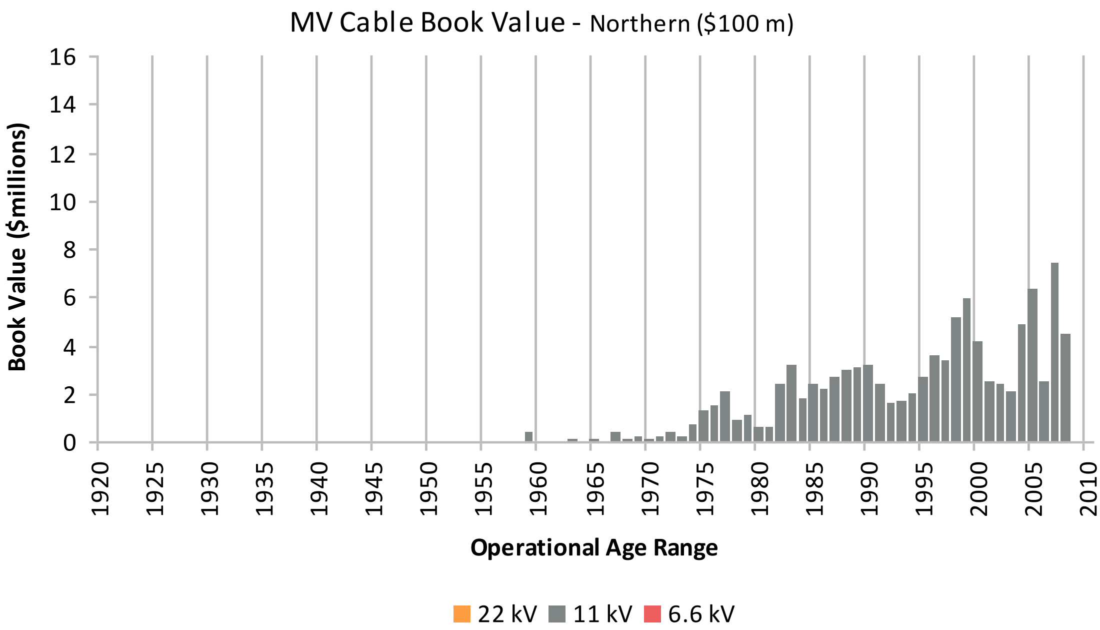


Figure 6-46 : MV cable book value – Northern

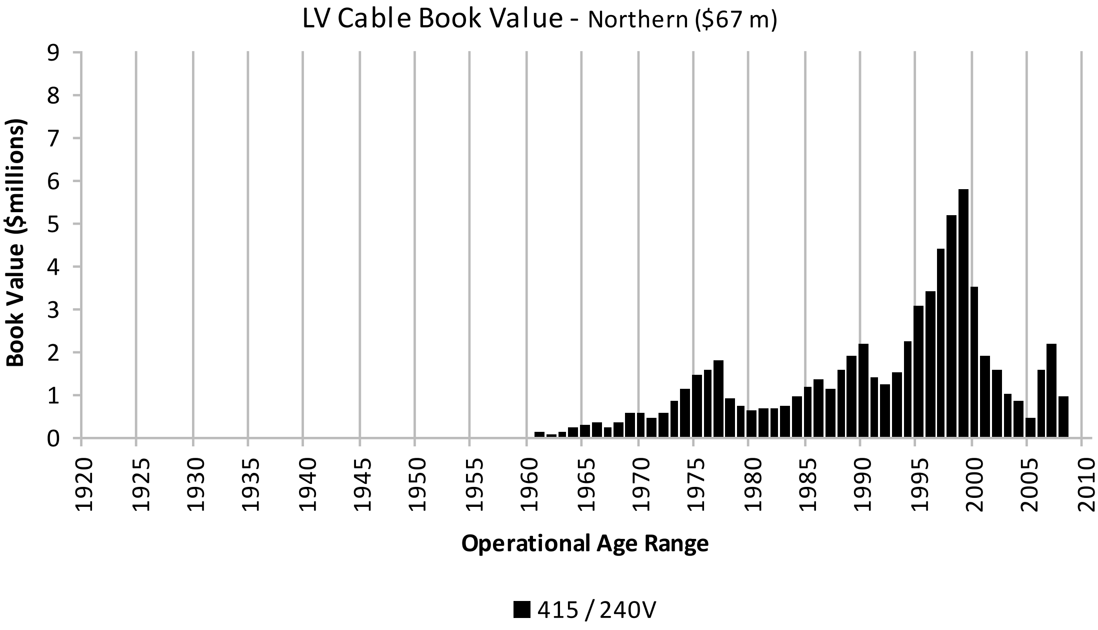


Figure 6-47 : LV cable book value - Northern

6.3.14.1 Asset Condition

The 6.6kV cables energised at 6.6kV are operating satisfactorily. Some 6.6kV cables which have been uprated to operate at 11kV are showing signs of failure although based on available evidence at the time of the uprate that the 6.6kV cables were capable of operating at 11kV. The issues are further discussed below.

The 11kV 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:

- 22kV cables - these cables are still very new and, as would be expected, there are no known issues;
- 11kV cables - in the early 1970s natural polyethylene insulated 11kV cable was installed on the Northern network. This type of cable has a high fault incidence and Vector's current policy 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 are soon to follow - hence the decision to move forward with a programmed replacement;
- 6.6kV cables - some cables have been upgraded to 11kV operation, which has created issues. Some of the issues are due to failure of the joints (workmanship and insulation only designed for 6.6kV) and other problems are due to insufficient cable insulation;
- The issues are compounded by the fact that historical records of the cables are not always correct, with some cables indicated as being rated for 11kV where this later proves not to be the case. The full extent of the issue is still to be confirmed, as confirmation of the actual voltage rating of an operating cable requires that it be opened up and the insulating papers counted to confirm suitability for operation at 11kV (which cannot be done in normal operating conditions). Cables are treated on a case by case basis as faults occur;

- Vector also has an ongoing replacement programme for the remaining 6.6kV cables;
- 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 cables that earth pole-mounted equipment is theft for the scrap value of the Cu. The change of our standard to use Cu plated steel cables to combat this has almost eliminated the theft of new earthing cables.

6.3.14.2 Inspection and Test Programme

Power Cables

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 shows promise but is currently impractical given the large number of cables involved.

Earthing system

The earthing system is normally visually inspected for integrity on an annual basis, but with the recent theft of the Cu earth cables the inspections have been undertaken more frequently 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 compliant sites require step and touch voltage retesting using off-frequency injection current; and
  - Five yearly - ground based visual inspection of tank, bushings, support structure, desiccant breathers and vents, mounting fasteners, signage, clearances, wildlife and vegetation.
- 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;
  - All indentified transformer defects that are deemed likely to result in near future asset failure or environmental harm, e.g. serious oil leaks, tank or bushing damage, require imminent treatment or replacement;
  - All identified associated asset defects e.g.; support structure corrosion will be programmed for component repair/replacement unless a more viable option is considered appropriate;

    - All transformers being replaced undergo refurbishment viability assessment, however a first filter refurbishment assessment requires scrapping of:
        - Less than 50kVA capacity and units older than 45 years; and
        - Equal or greater than 50kVA capacity and units older than 55 years.
- Fault and emergency maintenance:
    - All indentified 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 injection current.

6.3.14.3 Maintenance, Refurbishment and Replacement Programme

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.

Underground cables are replaced when the failure rate becomes unacceptable. The benchmark level of unacceptability is considered to be no more than one fault per annum. At present Vector is targeting cables exhibiting the most frequent faults and exceeding this minimum level. Because of the generic fault history of natural polythene HV cable, these cables are being progressively replaced.

Earthing cables are only maintained if they are visibly unsound or undersized, or test results fall outside the limits given in Vector's distribution earthing maintenance standard.

Maintenance of pits and pillars is determined by the results of the inspection programme.

6.3.15 HV Pole Mounted Cable Terminations

Terminations are the connection points between underground cables and the overhead network and include all 6.6kV, 11kV, 22kV and 33kV pole terminations. There are different types of these terminations in service.

Table 6-19 below shows the breakdown by voltage class, network and value of HV pole terminations on the networks.

Population	33kV	22kV	11kV	6.6kV
Southern	11	2	2529	115
Northern	151	0	5368	0
TOTAL	**162**	**2**	**7897**	**115**
Book Value	**33kV**	**22kV**	**11kV**	**6.6kV**
Southern	$0.3m	$0.0m	$6.1m	$0.3m
Northern	$2.2m	$0.0m	$9.8m	$0.0m
TOTAL	**$2.5m**	**$0.0m**	**$15.9m**	**$0.3m**

Table 6-19 : Riser cable terminations - population and book value

Figure 6-48 to Figure 6-51 provide the age profiles and book values of cable terminations for each region, at the different voltage levels.

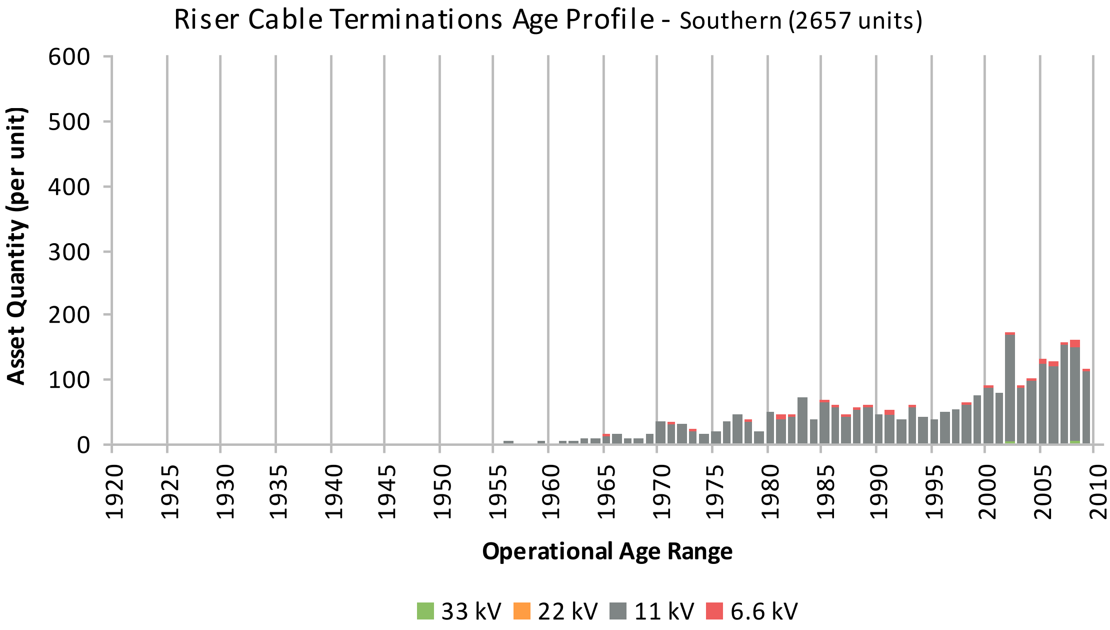


Figure 6-48 : Riser cable terminations age profile – Southern

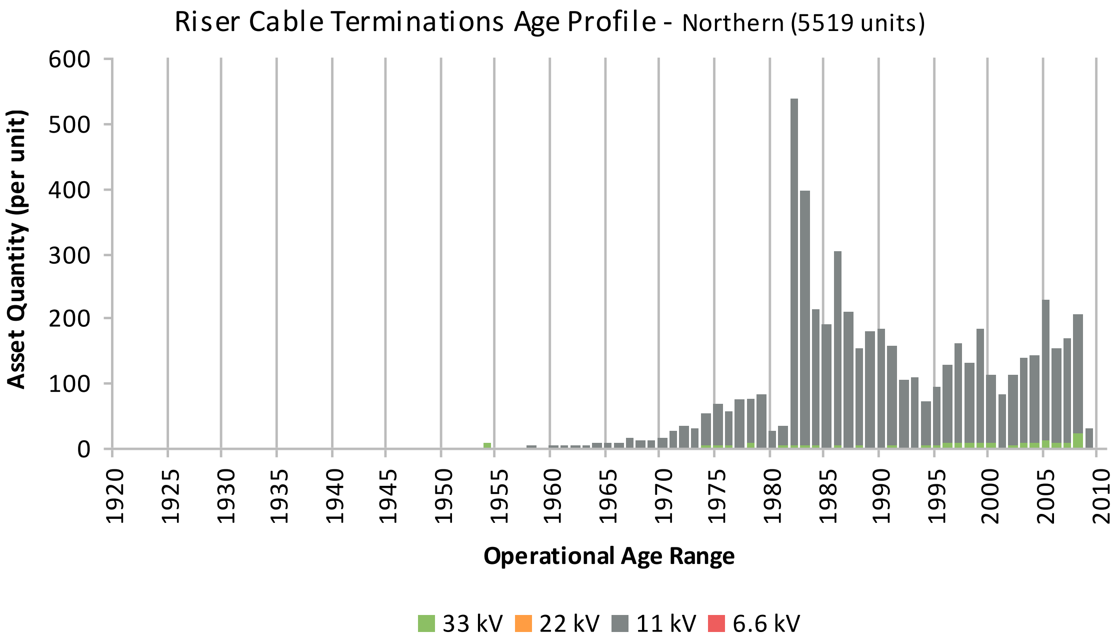


Figure 6-49 : Riser cable terminations age profile – Northern

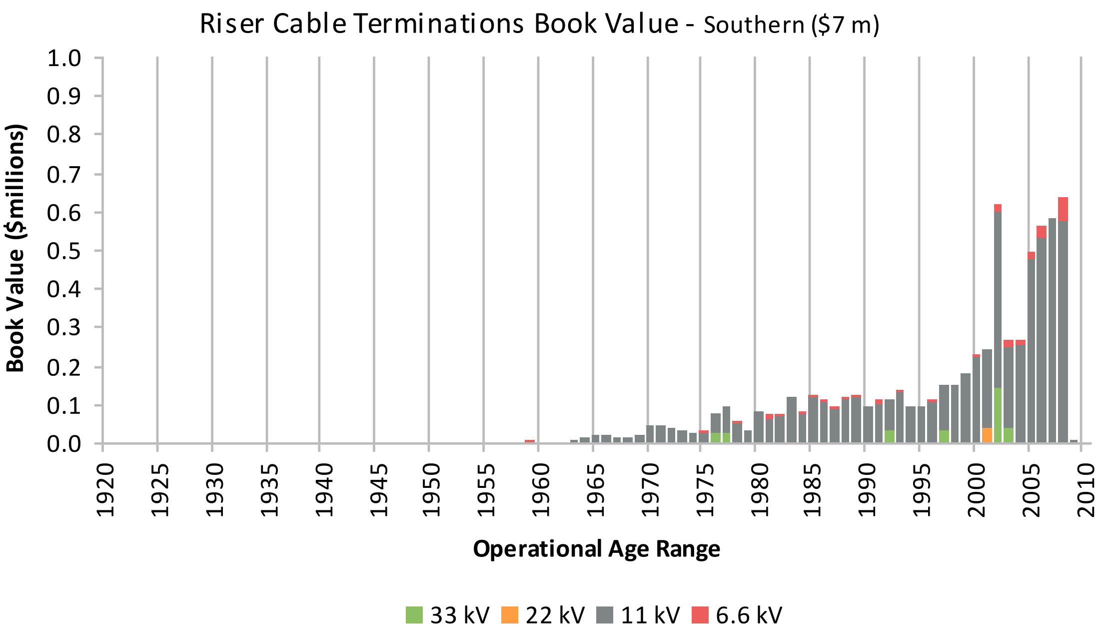


Figure 6-50 : Riser cable terminations book value – Southern

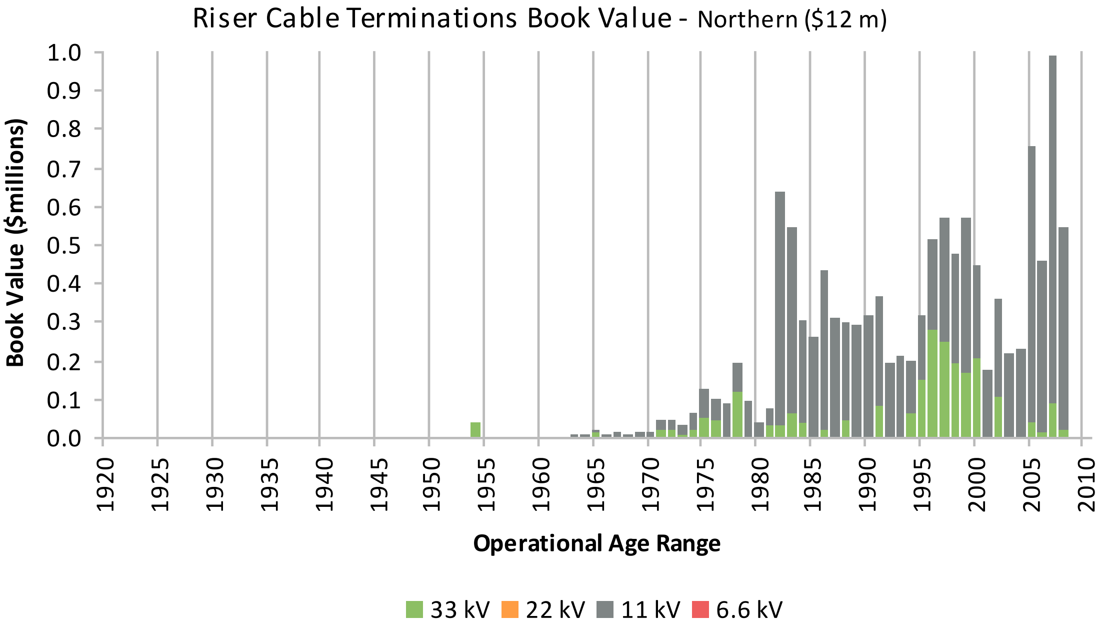


Figure 6-51 : Riser cable terminations book value – Northern

6.3.15.1 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 is encountering cable pole terminations where the connection between the underground cable and the overhead reticulation jumper is by two lugs bolted together at a standoff insulator. The issue arises at installations where a steel nut or washer has been placed between the two lugs, resulting in a high resistance connection between the underground cable and the jumper. The heating of the nut/washer is sufficient to cause the termination to fail. Terminations of this nature have largely been located and corrected with a programme currently underway to identify and correct the remaining units.

Vector's overhead network condition assessment ENS-0187 standard specifically targets the identification of 3M terminations and of interposing nut/washer terminations, to enable us 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, but some of the old terminations were recently found in a CB cable box during a shutdown at a zone substation. These will be replaced as they are 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 steadily removed from the Vector network.

6.3.15.2 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 & 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, LV fuses, 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 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; and
- Fault and emergency maintenance:
  - Any identified defect that is likely to pose an imminent hazard to public and property is repaired, replaced or isolated immediately.

6.3.15.3 Maintenance, Refurbishment and Renewal Programmes

Maintenance of cable terminations is limited to correcting defects that are visually identified during the annual overhead inspection.

Cable terminations are generally operated to failure in line with industry practice and therefore, with the exception of the cast metal unit plan, Vector has no refurbishment or preventative replacement programmes in place. Cast metal terminations are being steadily proactively replaced because of safety concerns when one of these terminations fails.

3M cold applied terminations will be programmed for replacement when sufficient numbers have been located.

6.3.16 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 and 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 6-20 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	78716	$47.4m
Northern	21550	$15.7m
TOTAL	**100266**	**$63.2m**

Table 6-20 : Service connections - population and book value

Figure 6-52 to Figure 6-55 show the pillar and pit age profiles and book values for each region.

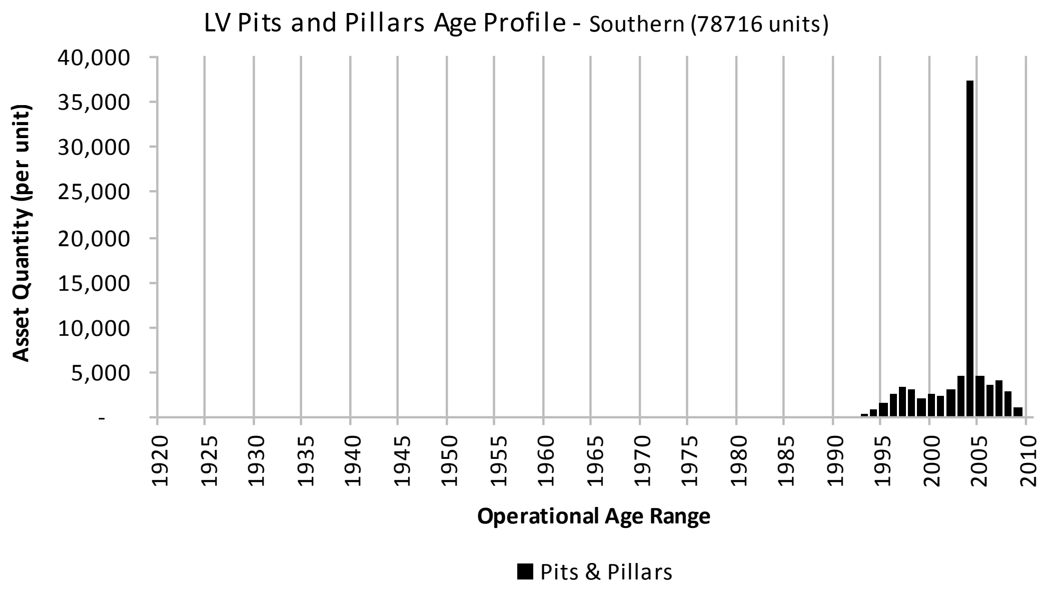


Figure 6-52 : LV pits and pillars age profile - Southern

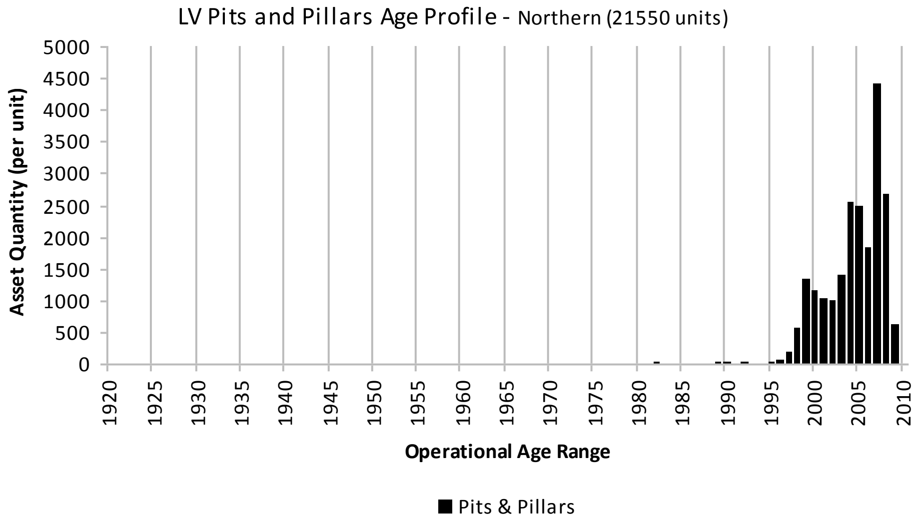


Figure 6-53 : LV pits and pillars age profile - Northern

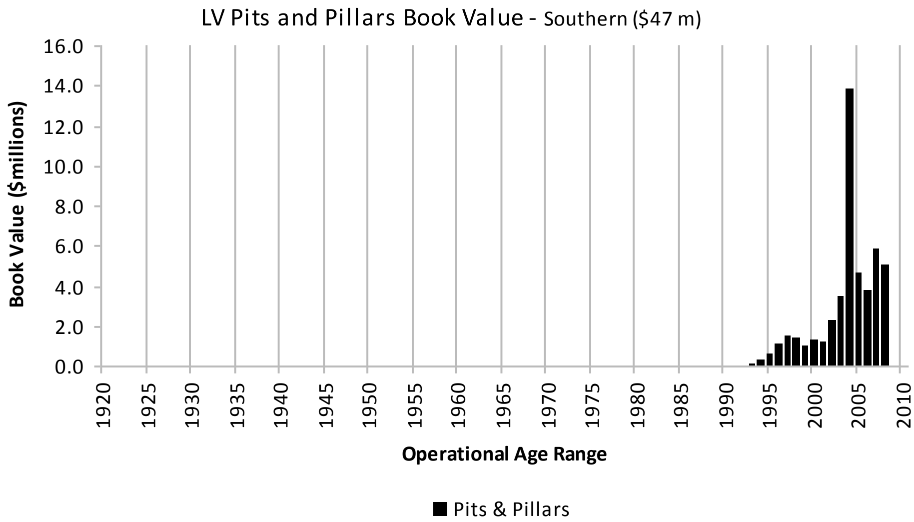


Figure 6-54 : LV pits and pillars book value - Southern

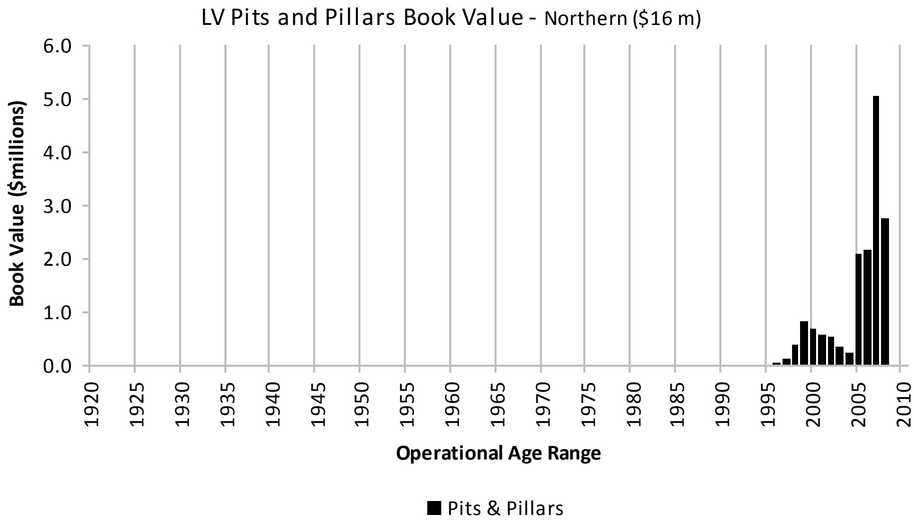


Figure 6-55 : LV pits and pillars book value - Northern

6.3.16.1 Asset Condition

The condition of 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.

The mushroom pillars used in the Northern area have deteriorated to the extent that they could be hazardous to Vector's contractors. These pillars are being systematically replaced by a polyethylene pillar with similar dimensions.

6.3.16.2 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 & 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;
- Refurbish 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 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;
  - Minor repairs on site include removal of vegetation, replacement of lid screws, new connectors, corrosion treatments, repainting; and
- Fault and Emergency Maintenance:
  - Hazardous defects identified resulting in potential unsafe situations for public or property, are repaired, replaced or isolated immediately.

6.3.16.3 Maintenance, Refurbishment and Renewal Programme

Where practicable, pillars are repaired on site following faults or reports of damage. Otherwise a new pillar or pit or network box is installed.

With the exception of the mushroom pillars, there is no general replacement programme. 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.

6.3.17 Distribution Transformers

Distribution transformers convert distribution voltage levels (typically 22kV, 11kV and 6.6kV) to customer voltage levels (typically 400V three phase or 231V 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.

The windings are made of Cu or aluminium wire or foil. The heat generated by a transformer is removed by the ambient air passing over the transformer tank and circulation of the oil through the radiators that are also cooled by the ambient air.

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 1,500kVA. Most transformers are three phase, with the exception of 30kVA pole mounted, 15kVA ground mounted and 30KVA ground mounted units (which are single phase). There are also a small number of single phase transformers rated at 1.5kVA, 5kVA, 7.5kVA and 10kVA. The three phase transformer windings are connected delta/star in accordance with Vector group reference Dyn11.

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, mini substation 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 ground mounted transformers 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, H structures or 1.5 pole structures. The transformers are connected to the HV and LV networks by cable lugs and bolted connections to the transformer bushing flags.

With the development of the 22kV underground distribution network in the Southern CBD and Highbrook Business Park, 22kV/415V ground mounted transformers are also being used. 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 have been supplied by the following manufacturers: Asea, Asea Brown Boverie (ABB), Asea Tolley Electric Construction (ASTEC), Canadian Australian New Zealand Associated Cables (CANZAC), Brown Boverie Company (BBC), British Thompson Houston (BTH), Electric Construction Company (ECC), Electrical Transformer Engineering Limited (ETEL), Ferranti, Power Construction Limited (PCL), Tolley, Tyree, Tyree Power Construction (TPC), Turnbull and Jones, Waitemata Electric Power Board (later Waitemata Electric Manufacturing Company), and Wilson.

New transformers are currently supplied by either ABB or ETEL.

GIS records indicate there are 22,839 distribution transformers on Vector's network, 62% of which is ground mounted units (14,018 - 6,150 on the Southern network and 7,868 on the Northern network) and 38% pole mounted (8,821 - 2,238 on the Southern network and 6,583 on the Northern network).

The Optimised Deprival Value (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 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 Figure 6-56 to Figure 6-59.

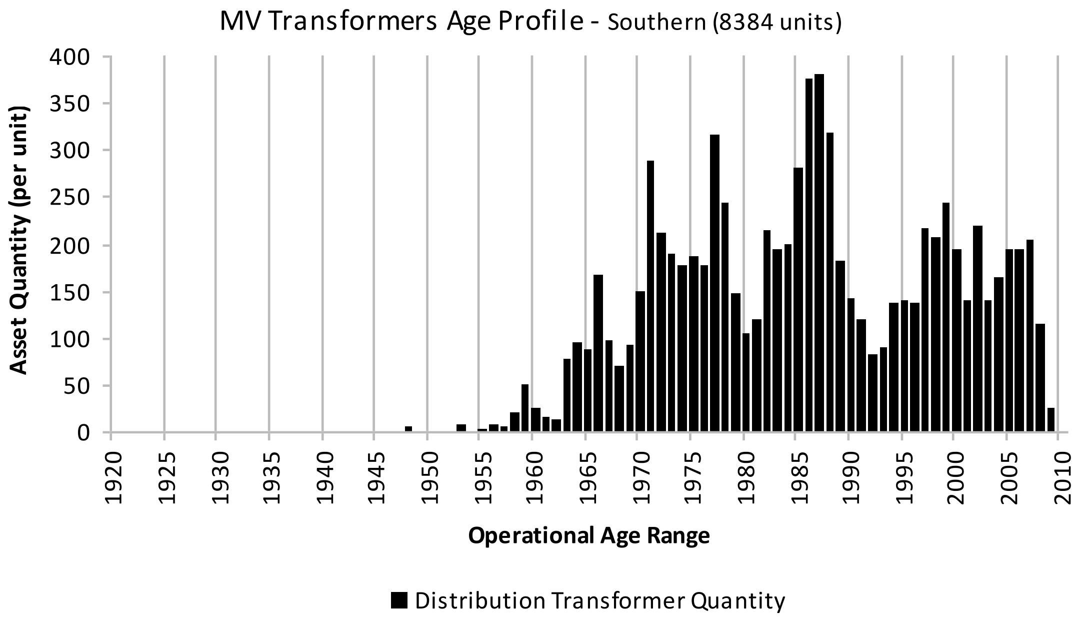


Figure 6-56 : MV transformers age profile - Southern

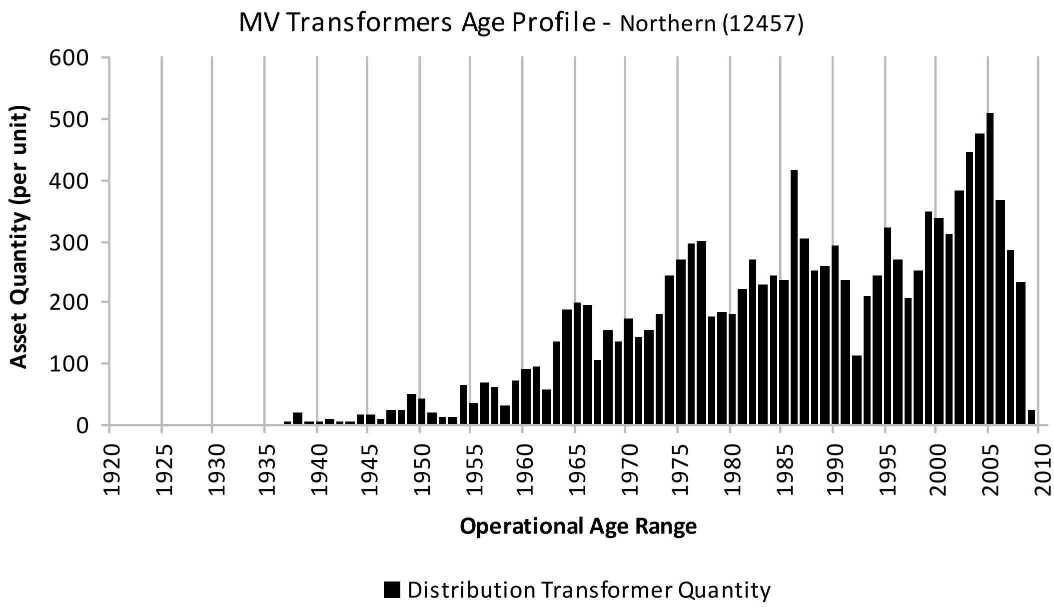


Figure 6-57 : MV transformers age profile – Northern

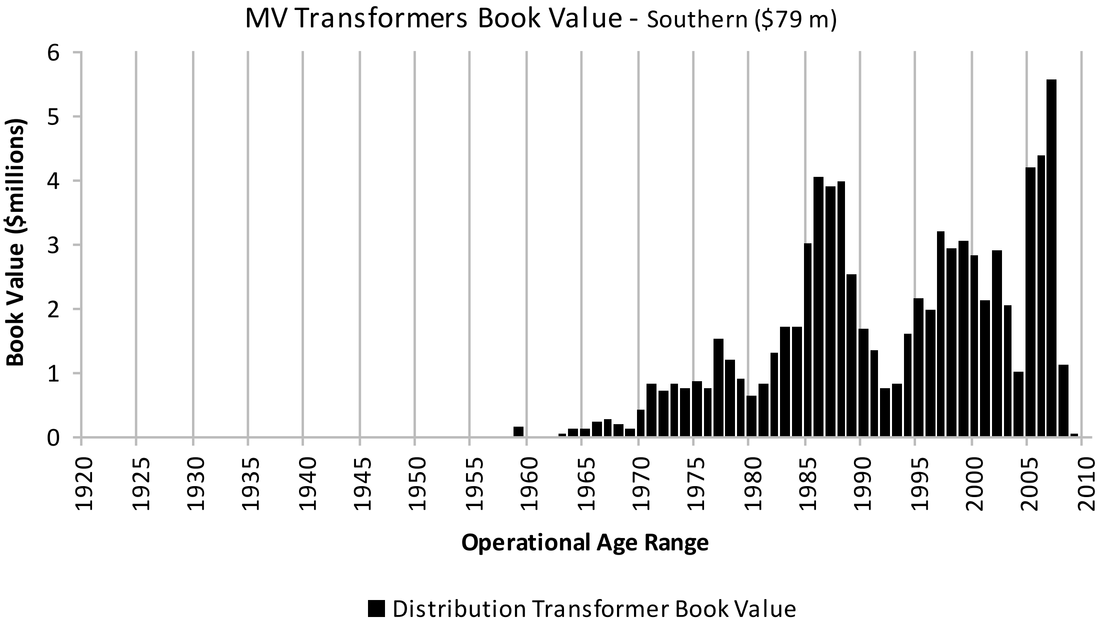


Figure 6-58 : MV transformers book value - Southern

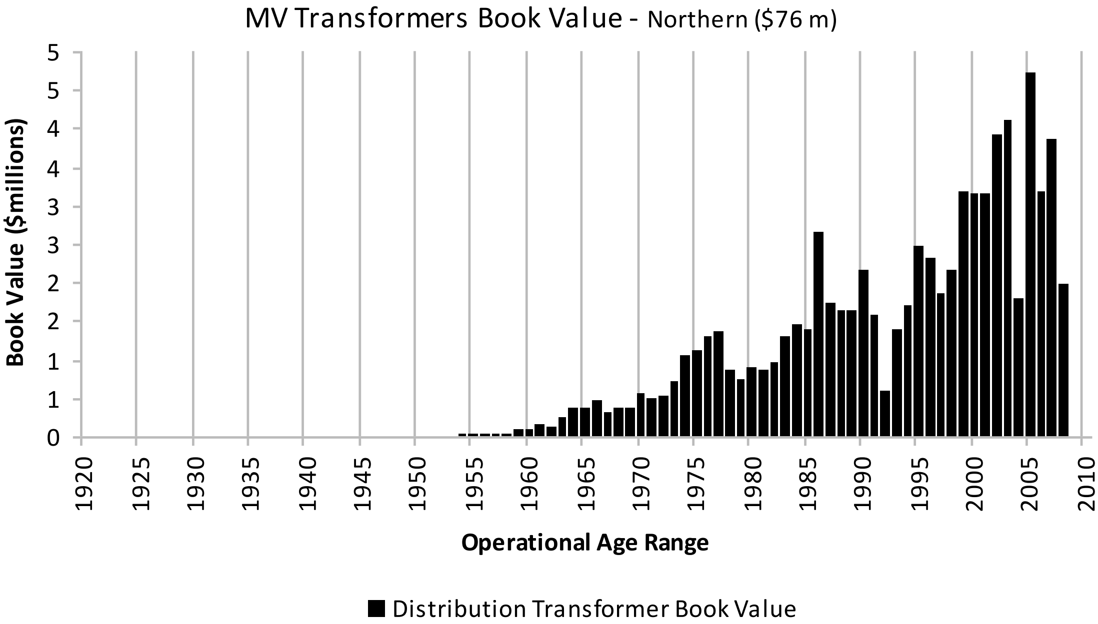


Figure 6-59 : MV transformers book value - Northern

6.3.17.1 Asset Condition

In general the condition of the majority of transformers is good. Many of those that were in poor condition have been replaced since 2001 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 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;

- Ground mounted transformers about 25 years old have increased risk of non-compliance due to excessive rust or oil leaks. This is estimated to be 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 painting coating system.

These transformers are being systematically replaced in accordance with Vector's current renewal process.

6.3.17.2 Inspection and Test Programme

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.

In late 2007 and early 2008 a trial testing of the oil in ground mounted transformers was carried out at nine major customer sites. The results showed that of the nine locations, seven transformers were in good condition and the other two required further internal transformer investigation. It is not clear that it is economically valuable to extend the trial and it has been put on hold, pending further analysis of failure trends of distribution transformers.

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 PCBs – which is classed as a non PCB liquid.

Thermal imagining and testing for PD is presently carried out as part of the transformer inspection programme. The value of these tests is being reviewed and both may be discontinued in the near future.

6.3.17.3 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, minor rust treatment and paint repairs. Where it is uneconomical 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 it is Vector's approach to assess the condition of distribution transformers and proactively replace these based on the assessment (or where a change in capacity is required).

Over the three calendar years 2006 to 2008, 576 transformers that had deteriorated excessively, were proactively replaced. Of that number, 223 were on the Southern network and 353 were on the Northern network.

However, over the same period 352 transformers faulted beyond economic repair and have been (reactively) replaced. Of that number 106 were on the Southern network and 246 were on the Northern network. This suggests that the condition-based assessment programme may have to be stepped up.

Transformers that are removed from service and are still in salvageable condition are refurbished. The decision criteria on whether to do so are described in Vector standard ENS-0170. Vector's stock requirements at the time are also considered. It is expected that a transformer will attain another 25 to 30 years of service after refurbishment.

Data obtained from inspections and tests is presently managed and analysed by Vector's contractors. With the planned commissioning of Vector's TAM system in April 2010, this situation will change. In future, analysis of the information will be carried out by Vector personnel, and this will form the basis of future replacement programmes.

A summary of ENS-0051 is given as follows:

- Routine & preventive maintenance:
  - Four yearly - visual inspection of transformer tank, bushings, desiccant breathers and vents, mounting fasteners, signage, clearances, wildlife and vegetation, including thermal camera PD and acoustic discharge inspections;
  - Four yearly – visual inspection of switchgear tanks, mounting fasteners, signage, vegetation, rubbish including thermal camera, PD and acoustic discharge inspections. In addition a live tank oil condition sample is taken the analysis of which is provided by TjH2B covers breakdown voltage, neutralisation value and water content;
  - Four yearly – visual inspections of buildings, enclosures and grounds. Scope covers associated electrical installations, lighting, heating and ventilation systems internal wiring and power points, vegetation and signage, ducts and trenches, floors, foundations, doors, gates, walls, fences, ceilings and roof; and
  - 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 compliant sites require step and touch voltage retesting using off-frequency injection current.
- 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;
  - Further corrective maintenance activities are triggered on:
    - Identified thermal hotspots greater than 10 degrees above surroundings;
    - Levels of acoustic discharge, significantly above background noise; and
    - Levels of PD, significantly above background noise.
  - All indentified transformer defects that are deemed likely to result in near future asset failure or environmental harm, e.g.; serious oil leaks, tank or bushing damage, require imminent treatment or replacement;
  - All identified associated asset defects e.g.; support structure corrosion will be programmed for component repair/replacement unless a more viable option is considered appropriate;
  - All transformers being replaced undergo refurbishment viability assessment, however a first filter refurbishment assessment requires scrapping of:

    - Less than 50kVA capacity and units older than 45 years; and
    - Equal or greater than 50kVA capacity and units older than 55 years.
  - The majority of defective switchgear being replaced is scrapped, with the exception of ABB series 2 SD type oil switchgear less than 15 years old; and
- Fault and emergency maintenance:
  - All indentified 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.

6.3.18 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 five ground mounted auto transformers and one phase shifting transformer on Vector's network. All are installed on the Southern network. Four of the auto transformers are 11kV/6.6kV and one is 22kV/11kV. The 11kV/6.6kV auto transformers are used in various locations on the Southern network as connections between the 11kV and 6.6kV networks. The remaining 6.6kV network is being presently changed to 11kV. The auto transformers capacities are 3.81MVA (2), 4.58MVA and 6.0MVA.

The 22kV/11kV auto transformer is used as a backup supply from Counties Power to the Vector network in East Coast Road, Kaiaua. Its capacity is 1.5MVA.

Auto transformers installed on the network have been supplied by ABB, Astec and Wilson.

The phase shifting transformer is 11kV/11kV, and is installed on the Southern region. It is used as a connection point between the Southern and Northern distribution networks. The transformer was manufactured by Pauwels and its capacity is 5MVA.

The year of manufacture for the 11kV/6.6kV auto transformers ranges between 1966 and 1987. The year of manufacture for the 22kV/11kV auto transformer is 2001 and for the phase shifting transformer is 2006. 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 6-21 below.

Network	Year of Manufacturer	Population	Book Value
Southern	1966	1	$0.02m
Southern	1986	1	$0.02m
Southern	1987	1	$0.02m
Southern	2001	2	$0.06m
Southern	2006	1	$0.18m
Total (units)		**6**	**$0.29m**

Table 6-21 : Auto transformer population and book value

The condition of the 11kV/6.6kV auto transformers is fair. These transformers will be either sold or scrapped when the remaining 6.6KV network is changed to 11kV. The voltage change is planned for completion by August 2010.

The condition of the 22kV/11kV auto transformer and the phase shifting transformer is very good.

6.3.18.1 Inspection and Test Programme

Inspection of auto transformers and the 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 testing for PD is presently carried out as part of the inspection programme. The value of these tests is being reviewed and checks on the 22kV/11kV auto transformer and the phase shifting transformer may be discontinued in the near future.

Transformer Condition Analysis (TCA) on oil samples from the auto transformer and phase shifting transformer is not presently carried out. It is proposed that this test for these transformers be added to the activities carried out by service providers.

6.3.18.2 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.

There is no refurbishment programme for the 11kv/6.6kV auto transformers as they will be sold after the 6.6kV network is changed to 11kV. Due to the relatively young age of the 22kV/11kV auto transformer and the phase shifting transformer, their good condition and their economic life, there is currently no refurbishment programme for these units.

There is no replacement programme for auto transformers or the phase shifting transformer.

A summary of ENS-0051 is given in Section 6.3.17.3 above.

6.3.19 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 two sites on the Southern network and two sites on the Northern network. All the voltage regulators installed on the network have been supplied by Siemens.

Southern network - there are three single phase 11kV 220kVA ground mounted regulators which are connected in closed delta at one site. At the other site there are two single phase 11kV 220kVA ground mounted regulators connected in open delta.

Northern network - there are two single phase 11kV 165kVA pole mounted regulators which are connected in open delta at one site. At the other site there is a three phase 11kV 417kVA ground mounted regulator.

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 6-22 .

Network	Year of Manufacture	Population	Book Value
Southern	1997	5	$0.35m
Northern	2001	2	$0.08m
Northern	2007	1	$0.61m
TOTAL (units)		**8**	**$0.61m**

Table 6-22 : 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.

The mechanical and electrical condition of the three phase regulator is very good as it was removed from service, refurbished and repainted to Vector's standard following a switching incident in June 2009.

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 manufacturer has acknowledged that there were issues with the painting process at the factory and the cost of refurbishment of the single phase regulators is being pursued with the manufacturer.

6.3.19.1 Inspection and Test Programme

Inspection of voltage regulators is carried out in accordance with Vector standard ENS-0188. The frequency of inspection is five 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 as part of the inspection programme. The value of this test is being reviewed and it may be discontinued in the near future.

TASA on oil samples from the voltage regulators is carried out annually.

6.3.19.2 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 lengthy periods (20 or more years) and as such there are no planned replacement programmes.

6.3.20 Ground Mounted Distribution Switchgear

Ground mounted distribution switchgear operates at 22kV, 11kV or 6.6kV 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 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-103.

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 6.6kV and 24kV units. 24kV rated SF switchgear is installed on the 22kV distribution networks in the Southern CBD and Highbrook Business Park. Definitions of the various categories of switchgear on the network are detailed in Table 6-23 below, while the manufacturers and models of the types used are detailed in Table 6-24.

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, arc-quenching medium is SF_6 or vacuum.

Table 6-23 : 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
	Ormazabal	GA

Table 6-24 : Switchgear type, manufacturer and model

GIS records indicate there are 9,938 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 6-25 provides a summary of the number of switchgear units on the network, as well as the book value.

Population	22 kV	11 kV	6.6 kV	Total
Southern	132	7115	114	7361
Northern	0	2182	0	2182
Total	**132**	**9297**	**114**	**9543**
Book Value	22 kV	11 kV	6.6 kV	Total
Southern	$ 0.1 m	$ 49.8 m	$ 1.0 m	$ 50.9 m
Northern	$ 0.0 m	$ 21.6 m	$ 0.0 m	$ 21.6 m
Total	**$ 0.1 m**	**$ 71.3 m**	**$ 1.0 m**	**$ 72.4 m**

Table 6-25 : Distribution switchgear population and book value

An age profile of Vector's ground mounted distribution switchgear on each network is shown below in Figure 6-60 and Figure 6-61 and the book values are presented in Figure 6-62 and Figure 6-63.

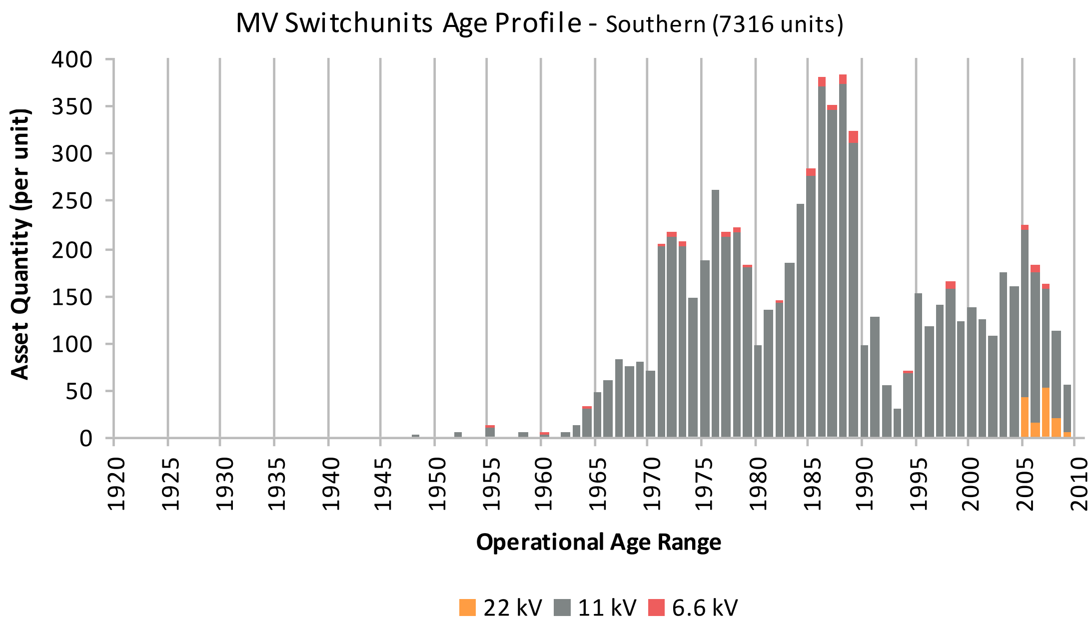


Figure 6-60 : MV switch unit's age profile – Southern

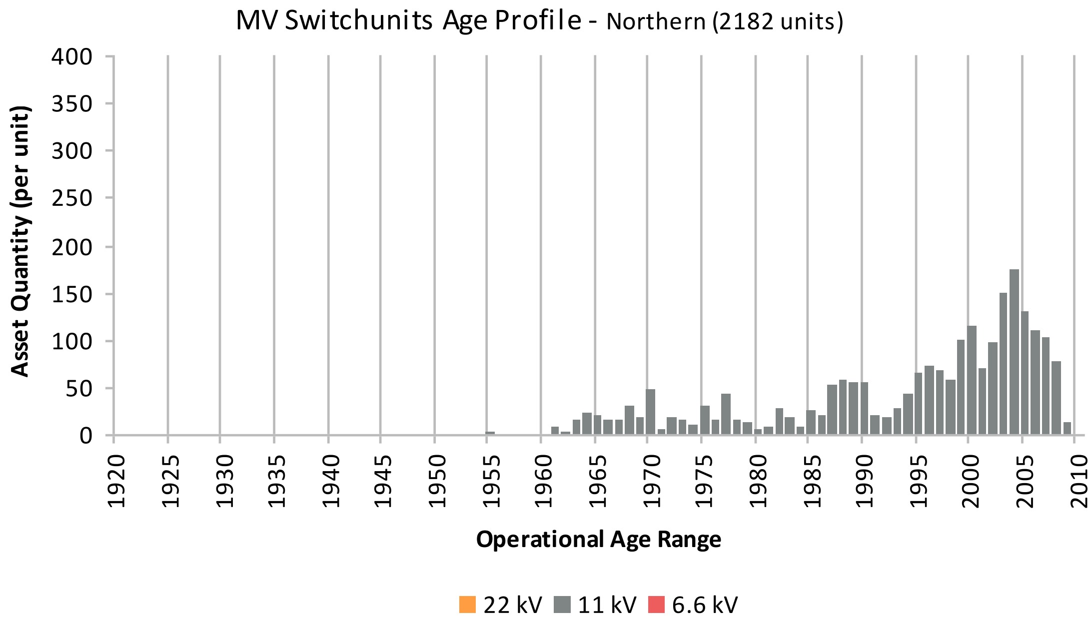


Figure 6-61 : MV switch unit age profile – Northern

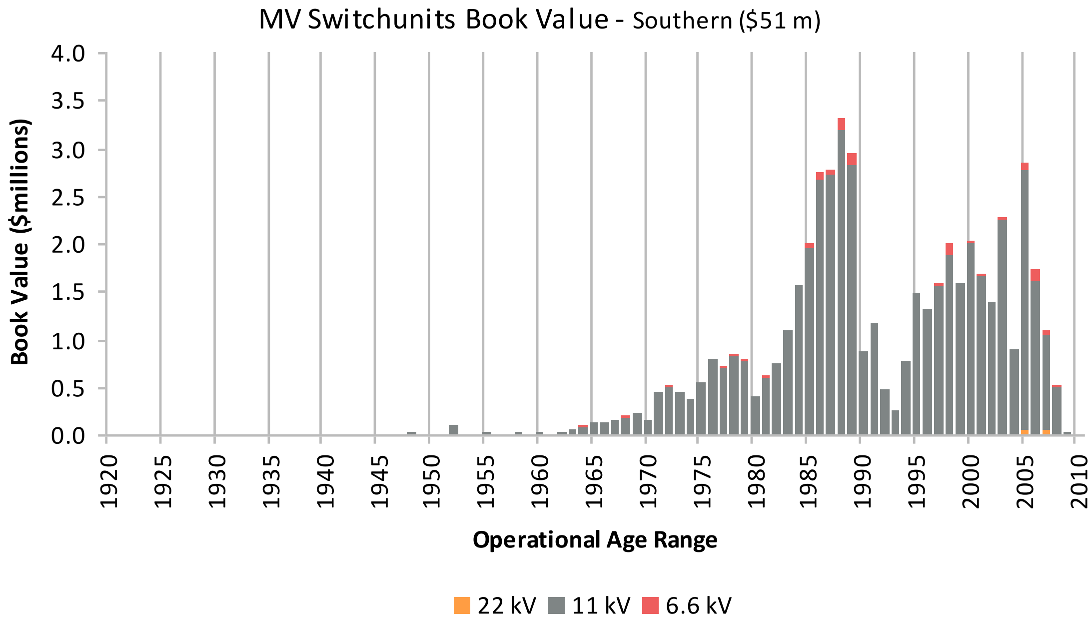


Figure 6-62 : MV switch-units book value - Southern

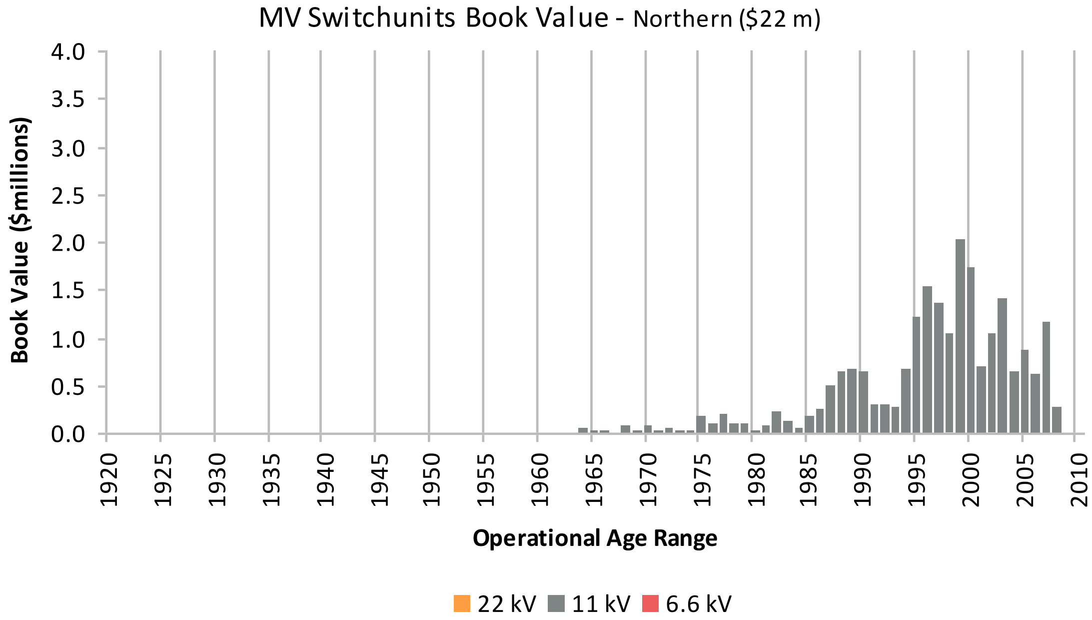


Figure 6-63 : MV switch-units book value - Northern

6.3.20.1 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. Some of those units have been replaced. Additionally some 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 a 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 over the past year and a root-cause analysis is being carried out to determine the solution;
- 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. The number of switches involved is being determined and a remedial programme is planned for completion by July 2011; and
- There is no indication of the oil level in Andelect Series 1 SD switch gear. 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.

6.3.20.2 Inspection and Test Programme

Inspection of distribution switchgear is carried out in accordance with Vector standard ENS-0188. The frequency of inspection is eight yearly.

Thermal imaging and testing for PD is also carried out as part of the inspection programme. The value of these tests is being reviewed and both may be discontinued in the near future. Present day PD and thermal imaging techniques are heavily dependent on operator skill and interpretation of the results. They are also greatly affected by the environmental and network operating conditions at the time of the test. These tests are not definitive in determining if there is an impending fault, except perhaps in the extreme.

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 a live tank oil sample (LTOS) is taken from a switch unit during the scheduled inspections, and analysed. The procedure is carried out in accordance with Vector instruction ENI-0036. The results determine when maintenance needs to be carried out on the internals of the unit or when further oil samples should be taken.

Testing of the automation of automated switchgear is not currently included in the Multi Utility Services Agreements (MUSA) with our FSPs and is not carried out. Vector is considering whether to include this task as an addition to the agreements.

6.3.20.3 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.

Over the three calendar years 2006 to 2008, 49 switch units whose condition met the criteria for replacement have been replaced. Of that number, 32 were on the Southern network and 17 were on the Northern network.

Up until September 2009, switchgear has been removed from service and transported to the company that refurbishes Vector's transformers and switchgear for assessment and refurbishment or scrapping. Approximately 110 switch units a year are assessed for refurbishment, of which roughly 18% are refurbished. As Vector will soon be issuing a Request for Proposal (RFP) for the supply of 22kV and 11kV distribution switchgear (other than oil-filled), the refurbishment programme has been suspended.

In addition to replacement of switchgear due to corrosion or the results of LTOS tests, it is intended to implement a replacement strategy for cast resin and oil-filled switchgear which is 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 switch units. Andelect switch units have a history of failure and unreliability due to a poor design that cannot be economically rectified.

Approximately 100 Andelect oil-filled units that are older than 25 years have been identified as top priority for replacement. They are to be replaced as soon as possible.

A further 720 Andelect oil-filled units that 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. They are to be replaced over the next five to ten years.

Moderate priority replacements that have been identified are 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.

6.3.21 Distribution Equipment Enclosure

Distribution equipment enclosures are used to accommodate Vector's ground mounted distribution equipment. There are many types of enclosures and 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.

GIS records indicate there are 14,840 distribution equipment enclosures on Vector's network, with 6,655 on the Southern network and 8,185 on the Northern network. An age profile of Vector's equipment enclosures on each network and associated book values are shown in Figure 6-64 to Figure 6-67.

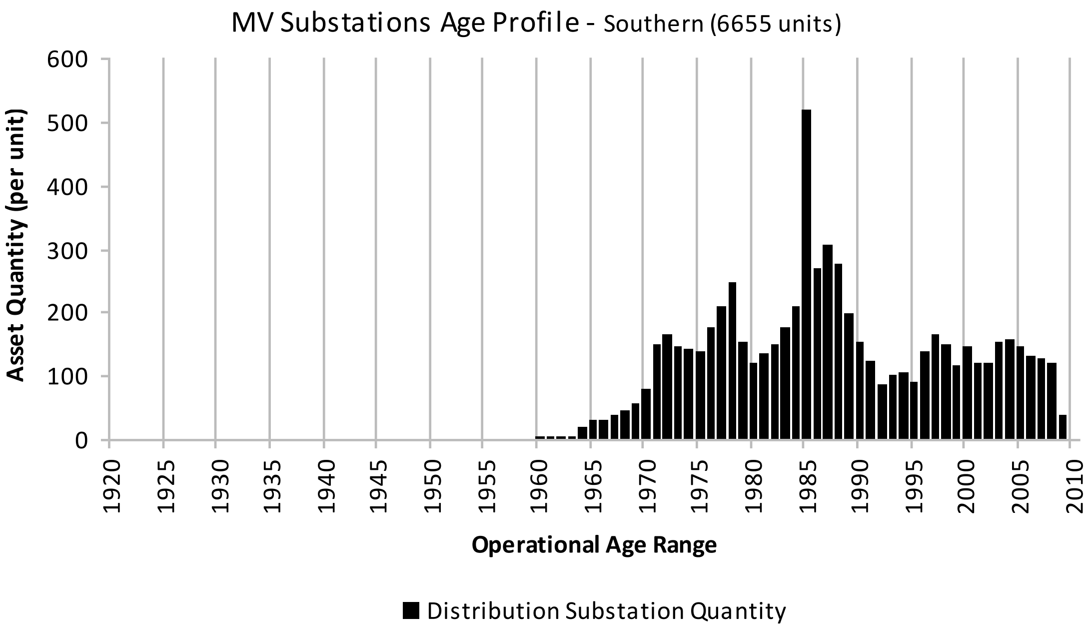


Figure 6-64: MV substation age profile – Southern

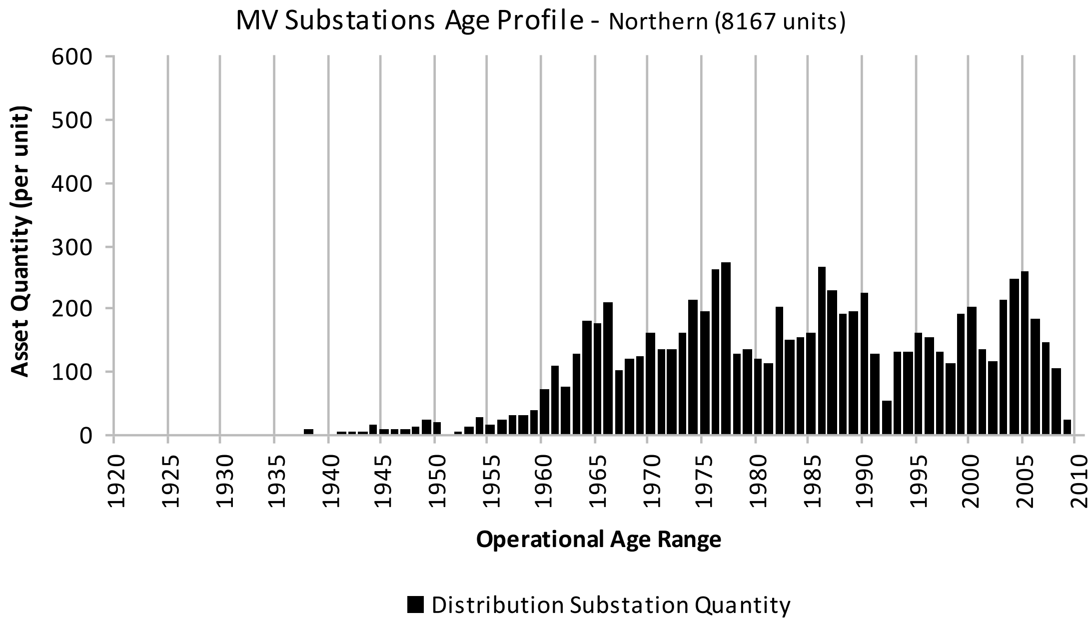


Figure 6-65 : MV substation age profile – Northern

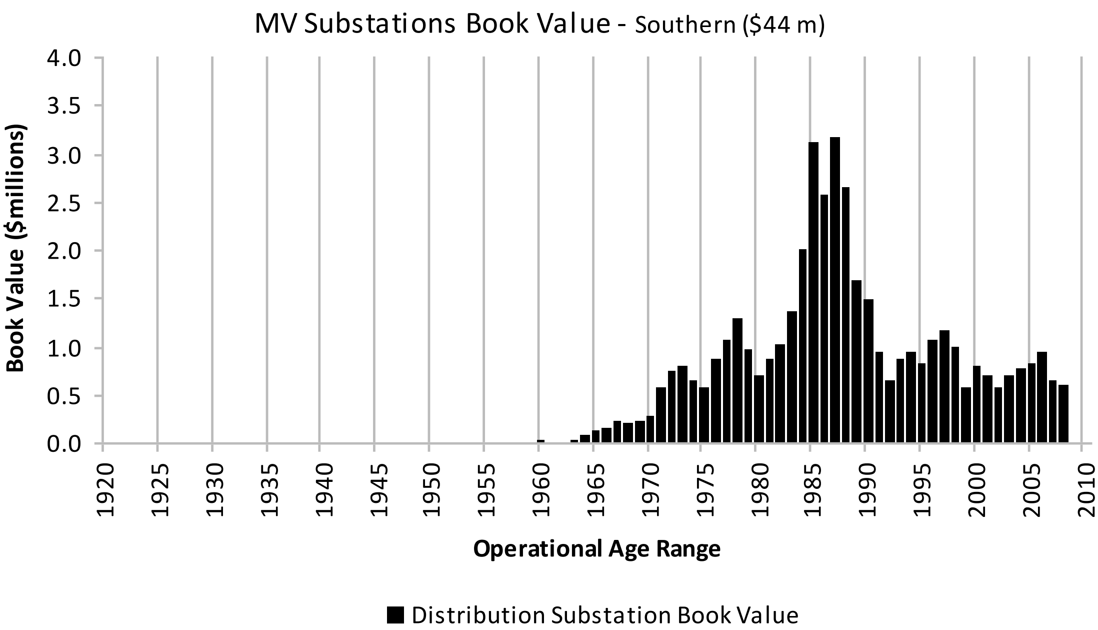


Figure 6-66 : MV substation book value – Southern

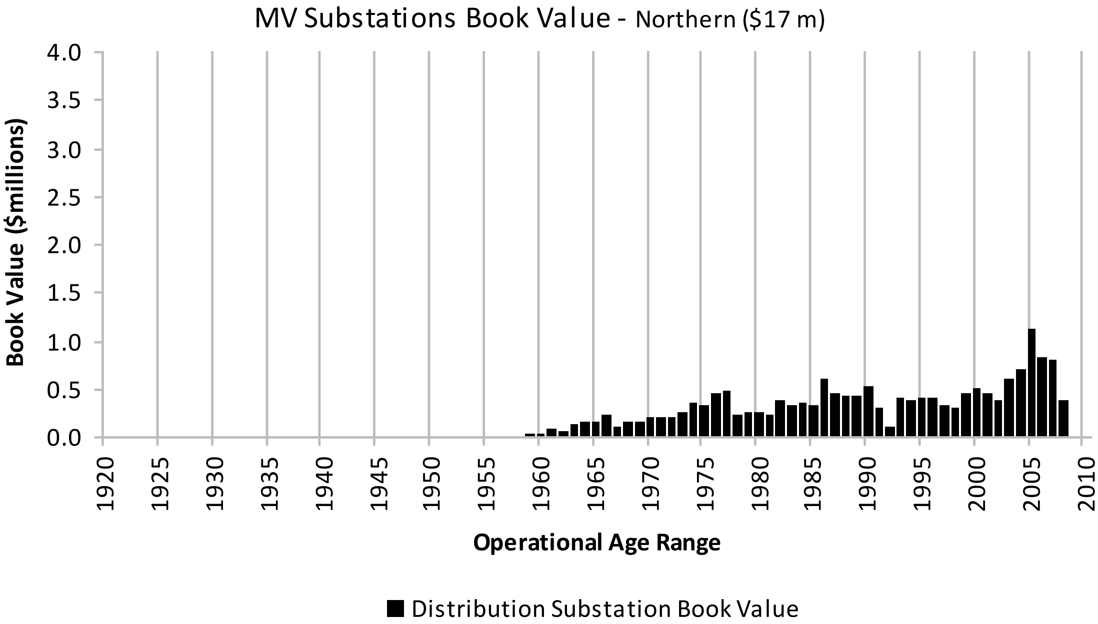


Figure 6-67 : MV substation book value – Northern

In general the condition of the majority of distribution equipment enclosures is good. There are no systemic issues.

6.3.21.1 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 on the enclosures.

6.3.21.2 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.

6.3.22 Low Voltage Switchboards and LV Frames

An LV switchboard consists of a number of fuses or 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. The fuses are connected to cables which supply customers. 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.

Vector has not developed a network standard for the supply of LV frames. There are two types of fusing installed on LV frames - JW type and DIN type. 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).

6.3.22.1 Asset Condition

LV switchboards are generally in good condition.

LV frames of both types are generally in good condition.

There have been operational issues with JW type LV frames. On both types of frame there have been incidents (overheating and fires) due to a poor connection between an LV cable or bus bar and a fuse.

6.3.22.2 Inspection and Test Programme

There are no inspection programmes for LV switchboards or frames.

Thermal imaging is carried out on LV frames every four years.

6.3.22.3 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.

6.3.23 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 75 pole mounted 11kV capacitor banks each rated at 750kVAr.

The 11KV capacitors in both regions were installed during 1998/99. The pole mounted banks are in good condition. 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 and 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.

The 11kV capacitors located in the Southern region zone substations are in need of maintenance.

6.3.23.1 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).

6.3.23.2 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 (ENS-0048).

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 (ENS-0192).

The existing pole mounted capacitors are only repaired where salvaged components are available for the repair. The zone substation 11kV capacitors are to be maintained in an operational state.

There is no currently planned replacement for the 11kV capacitors.

6.3.24 Energy and Power Quality Metering System

Asset Description

There are 53 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 6-26 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 revenue metering installation. The meters are connected to check metering instrument transformer owned by Transpower. The meters also receive pulse streams from the Transpower metering system and provide comparison 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 Energy and Power Quality Metering System is estimated to be $2 million.

Age Profile

These assets have an expected technical life of 15 years.

Network	Type	Year of Manufacturer	Population
Northern	ION 7650	2007	4
Northern	ION 7650	2008	1
Northern	ION 8500	2003	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 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)			**53**

Table 6-26 : Combined energy and power quality meters

Condition of the Asset

The metering asset is in good condition.

Maintenance Program

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.

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 6-27 : Vector's Network – metering system maintenance costs 2010 to 2020 ($million)

Replacement/Refurbishment/Expansion Program

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 110kV 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.

Planned capex over the next five years is given in the tables below:

Northern Network	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
GXP PQ and Check Metering	$0.07m	$0.07m	$0.07m	$0.07m	$0.07m	$0.07m	$0.07m	$0.07m	$0.70m	$0.07m	$0.07m
Distribution Network PQ Metering	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m
Total	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**	**$0.17m**

Table 6-28 : Planned capex on metering equipment Northern network

Southern Network	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
GXP PQ and Check Metering	$0.10m	$0.00m	$0.00m	$0.00m	$0.00m	$0.10m	$0.00m	$0.00m	$0.00m	$0.00m	$0.10m
Distribution Network PQ Metering	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m	$0.10m
Total	**$0.20m**	**$0.10m**	**$0.10m**	**$0.10m**	**$0.10m**	**$0.20m**	**$0.10m**	**$0.10m**	**$0.10m**	**$0.10m**	**$0.20m**

Table 6-29 : Planned capex on metering equipment Southern network

Vector's Network	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PQ Software	$0.10m	$0.00m	$0.00m	$0.00m	$0.00m	$0.10m	$0.00m	$0.00m	$0.00m	$0.00m	$0.10m
Firmware Upgrade	$0.10m	$0.11m	$0.12m	$0.13m	$0.14m	$0.15m	$0.16m	$0.17m	$0.18m	$0.19m	$0.20m
Total	**$0.20m**	**$0.11m**	**$0.12m**	**$0.13m**	**$0.14m**	**$0.25m**	**$0.16m**	**$0.17m**	**$0.18m**	**$0.19m**	**$0.30m**

Table 6-30 : Planned capex on metering equipment Vector's network

6.3.25 Other Diverse Assets

6.3.25.1 Mobile Generator Connection Unit (MCGU)

Vector owns two MGCUs purchased in 2006 with a current 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 11kV network and multiple or single 415V diesel generators. Each unit has the capacity to inject up to 2.5MVA into the 11kV 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 6-68.

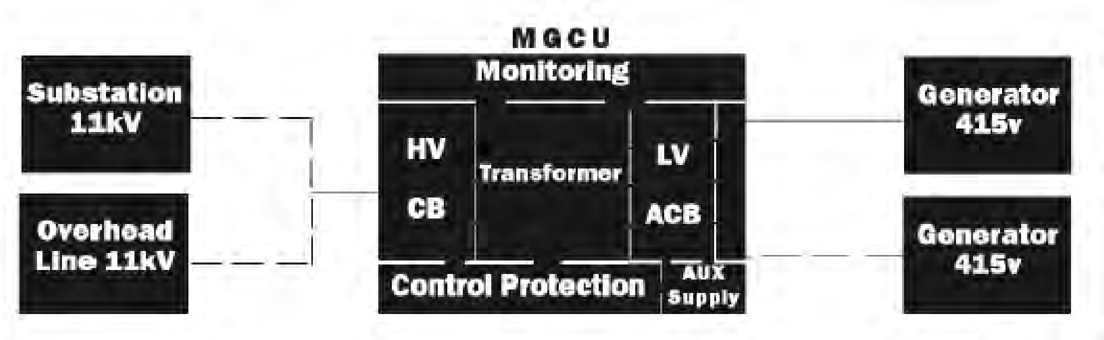


Figure 6-68 : Mobile generator connection diagram

The units are stored at and maintained by NZ Generator Hire.

6.3.25.2 Tunnels

Vector has a number of cable tunnels in its Southern network.

By far the largest single Vector asset is the 9200 meter by three meter diameter tunnel which extends from a shaft in the Penrose Transpower 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 22kV, 33kV and 110kV. 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 Vector-owned tunnels are minor in comparison, with the next longest being the Quay Street tunnel which is approximately 1000 metres in length along Quay Street with a 200 meter side tunnel to Emily Place. The Quay Street section is scheduled to be backfilled in 2010 due to concerns over its structural integrity. The cables in this tunnel operating at 11kV and 22kV will be run to failure and not replaced, as new circuits along alternate routes have already been established.

The other significant tunnels are:

- Swanson Street Tunnel - approximately 350 meters 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.

6.3.26 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[37].

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 that they may not be as cost effective as they use 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 refers 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 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.

[37] For example, working alongside other utility providers when they construct new footpaths or roads.

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 is a risk to the business and efforts to alleviate this by replacing legacy equipment on the networks is part of Vector's asset replacement prioritisation. (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 (220kV and above) levels and is not likely to be within the reach of distribution lines company for many years.

For Vector, traditional oil-filled transformers with Kraft paper insulation will 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 110kV.

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 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. To take advantage of this standard, 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.

6.5.1.5 Buildings and Structures

Vector's networks are experiencing strong growth. As a result Vector needs to establish several new substations over the coming years. Past practices of engaging architects, builders and designers for a bottom-up design is time consuming, inefficient, expensive and often results in less than optimal outcomes. Recognising this, Vector has put together a small team to establish a new template design for its buildings. This new design covers all aspects of the substation build from construction methodology to primary plant considerations, operator safety, and security as well as community impact considerations. The design has been used on the last several substations and the concept and design has evolved as a result of learning from previous builds.

The team is close to publishing the template base of design as a new Vector standard which will be used for all new zone substations. Use of this template will provide benefits through ease of construction, standardisation of design, robust materials and adherence to long-term design life of the build.

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 and 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

In an effort to remove oil-filled apparatus from distribution networks, it is planned to issue an RFP for the supply of distribution switchgear containing no combustible materials, in line with Vector's specification for MV switchgears 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.

6.5.2.4 Corona Camera

Corona discharge produces a narrow band of UV radiation. A Corona camera can detect this and has been trialled with the aim of detecting faulty overhead apparatus. This technology has shown some promise but it is dependent on the skill and interpretation of the operator. Like PD, as the technology becomes more developed, it is likely to become a more useful tool for the identification and prediction of imminent failure of OH connected apparatus.

6.6 Undergrounding of Overhead Lines

Vector, through an agreement with its majority shareholder, the Auckland Energy Consumer Trust (AECT)[38], 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 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 2009/2010 year is $12.5 million.

United Networks, when acquired by Vector in 2003, had embarked on an undergrounding programme in the areas of 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 trust ceased. Vector continued with this programme until the available funds in the 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 Rodney District, North Shore City, and Waitakere City since funding support from the Waitemata Electricity Trust ceased in 2005.

[38] This is a requirement of the Trust Deed.

6.6.1 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.

6.6.2 Projected OIP Expenditure

Vector's targeted investment in undergrounding for the 2009/2010 year is $12.5 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 6.31 below.

Financial Year	2010 /11	2011 /12	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20
Budget Amount ($M)	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7

Table 6-31 : OIP improvement budget

6.7 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). This matrix, in as far as it applies to renewal works, is described in Table 6-32.

	Priority Drivers						
Rank	Growth	Integerity	Customer	Legal & Regulation	Health Safety and Environment	Financial & Other	Operational Excellence
1	Capacity breach leading to asset damage	Reactive - critical assets	Utility driven relocations	Legal breach	Direct, serious safety threat	OIP	
			Contractual obligations with major breach consequences	Breach technical regulations	Direct, serious environment threat		
				Serious regulatory breach	Mitigation of extreme & very high direct risks		
					Critical cyber-security breach		
2	Other capacity breaches	Asset condition (1)	Other contractual obligations	Regulatory compliance & improvements	Anticipated serious safety issue	Avoiding financial “bleeding” on uneconomic assets	IT & information support critical for AI ops
			Other relocations		Anticipated serious environmental issue	Avoid severe reputation risk	
			New connections (NPV>0)		Mitigation of high direct risks		
			Capacity increases (NPV>0)		Serious cyber-security breach		
			Customer funded projects				
3	Security of supply breach	Asset condition (2)	Addressing (reasonable) customer expectations	Compliance with Vector technical policies & standards	Medium - Term HS&E Improvement Projects	Improved efficiency	IT & information support supporting effective AI ops
	Enhancing network efficiency	Power Quality Improvement				Allows capex deferral	Pilot projects, testing new initiatives
		Technical obsolescence				Avoid major reputation risk	
4	Safeguarding future options	Asset condition (3)	Other new connections			Other NPV>0 opportunities	
		Reliability improvements	Other capacity increases			Other reputation risks	
5	Nice to have; discretionary;						

Asset condition (1) = Severe deterioration of asset.
Asset condition (2) = Asset at end of technical life; increased risk of asset failure (and of material consequence), costing more to maintain and operate than to replace.
Asset condition (3) = Steady-state asset replacement programs.

Table 6-32 : Priority matrix for network integrity (renewal and replacement) projects

Based on the renewal requirements described in Section 6.3, and after applying the prioritisation criteria, the proposed network integrity (asset renewal or replacement) capex programme for the Southern network for the next five years is presented in Table 6-33. The Northern network expenditure programme is given in Table 6-34.

These programmes are combinations of specific renewal projects that have already been identified for specific (usually larger) assets, and allowances for renewal of repetitive assets, where the full actual extent of work will only become clear as inspections are carried out in future years.

Southern Network	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
11kV Indoor SB Replace Balmoral	-	-	-	$2.10 m	-	-	-	-	-	-
11kV Indoor SB Replace Liverpool Stage I	-	$3.00 m	-	-	-	-	-	-	-	-
11kV Indoor SB Replace Liverpool Stage II	-	-	$3.00 m	-	-	-	-	-	-	-
11kV Indoor SB Replace Manurewa	-	-	-	-	$2.10 m	-	-	-	-	-
11kV Indoor SB Replace Maraetai	-	$2.50 m	-	-	-	-	-	-	-	-
11kV Indoor SB Replace Onehunga	-	-	-	$2.10 m	-	-	-	-	-	-
11kV Indoor SB Replace Orakei	-	-	-	-	$2.10 m	-	-	-	-	-
11kV Indoor SB Retrofit Avondale	$0.55 m	-	-	-	-	-	-	-	-	-
11kV Indoor SB Retrofit Carbine	-	$0.55 m	-	-	-	-	-	-	-	-
11kV Indoor SB Retrofit Chevalier	-	-	$0.55 m	-	-	-	-	-	-	-
11kV Indoor SB Retrofit Greenmount	-	-	-	$0.15 m	-	-	-	-	-	-
11kV Indoor SB Retrofit Hans	-	-	-	$0.40 m	-	-	-	-	-	-
11kV Indoor SB Retrofit Hobson	-	-	-	-	$0.55 m	-	-	-	-	-
22kV Indoor SB Replace Kingsland	-	-	$4.00 m	-	-	-	-	-	-	-
11kV Indoor SB Replace	-	-	-	-	-	$4.00 m	$4.00 m	$4.00 m	$4.00 m	$4.00 m
11kV Indoor SB Retrofit	-	-	-	-	-	$0.55 m	$0.55 m	$0.55 m	$0.55 m	$0.55 m
Cable Replace	$1.48 m	$1.48 m	$1.48 m	$1.48 m	$1.48 m	$1.48 m	$1.48 m	$1.48 m	$1.48 m	$1.48 m
Crossarm Replace	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m
Earthing Upgrades	$0.20 m	$0.20 m	$0.20 m	$0.20 m	$0.20 m	$0.20 m	$0.20 m	$0.20 m	$0.20 m	$0.20 m
Ground Mounted Switchgear Replace	$0.42 m	$0.42 m	$0.42 m	$0.42 m	$0.42 m	$0.42 m	$0.42 m	$0.42 m	$0.42 m	$0.42 m
Hobson-Quay Tunnel Backfilling	$3.30 m	-	-	-	-	-	-	-	-	-
Pillar and Pit Replace	$1.39 m	$1.39 m	$1.39 m	$1.39 m	$1.39 m	$1.39 m	$1.39 m	$1.39 m	$1.39 m	$1.39 m
Pole Mounted Switchgear Replace	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m
Pole Replace	$6.71 m	$6.71 m	$6.71 m	$6.71 m	$6.71 m	$6.71 m	$6.71 m	$6.71 m	$6.71 m	$6.71 m
Power Transformer Replace 33/11	$1.50 m	-	$2.20 m	-	$2.20 m	-	$2.20 m	-	$2.20 m	-
Reconducting	$0.41 m	$0.41 m	$0.41 m	$0.41 m	$0.41 m	$0.41 m	$0.41 m	$0.41 m	$0.41 m	$0.41 m
Reliability Improvements	$2.10 m	$2.65 m	$2.65 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m
Strategic Spares	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m	$0.10 m
Sub-T Cable Replace Balmoral 22	-	$3.50 m	-	-	-	-	-	-	-	-
Sub-T Cable Replace Chevalier 22	-	-	-	-	$5.00 m	-	-	-	-	-
Sub-T Cable Replace Liverpool/Quay 22	-	-	-	$4.00 m	-	-	-	-	-	-
Sub-T Cable Replace Maraetai (FF) 33	-	-	$7.00 m	-	-	-	-	-	-	-
Sub-T Cable Replace Parnell 22	-	-	-	$3.00 m	-	-	-	-	-	-
Sub-T Cable Replace Ponsonby 22	-	-	-	-	$4.00 m	-	-	-	-	-
Sub-T Cable Replace Sandringham 22 (part B)	$3.00 m	-	-	-	-	-	-	-	-	-
Sub-T Cable Replace Takanini 33	-	-	-	-	$4.00 m	-	-	-	-	-
Sub-T Cable Replace	-	-	-	-	-	$6.00 m	$6.00 m	$6.00 m	$6.00 m	$6.00 m
Transformer Replace	$1.74 m	$1.74 m	$1.74 m	$1.74 m	$1.74 m	$1.74 m	$1.74 m	$1.74 m	$1.74 m	$1.74 m
Zone Sub Capacitors Replace	$0.49 m	$0.49 m	$0.49 m	$0.49 m	$0.49 m	$0.49 m	$0.49 m	$0.49 m	$0.49 m	$0.49 m
Zone Substation Oil Containment	$0.75 m	$0.75 m	$0.75 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m
Total	**$ 25.2 m**	**$ 27.0 m**	**$ 34.2 m**	**$ 27.3 m**	**$ 35.5 m**	**$ 26.1 m**	**$ 28.3 m**	**$ 26.1 m**	**$ 28.3 m**	**$ 26.1 m**

Table 6-33 : Proposed integrity capex - Southern

Northern Network	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
11kV Indoor SB Replace	-	-	-	-	-	$3.50 m	$3.50 m	$3.50 m	$3.50 m	$3.50 m
11kV Indoor SB Replace Balmain	-	-	-	$1.00 m	-	-	-	-	-	-
11kV Indoor SB Replace Browns Bay	-	-	$1.80 m	-	-	-	-	-	-	-
11kV Indoor SB Replace Laingholm	-	-	-	$1.00 m	-	-	-	-	-	-
11kV Indoor SB Replace Milford	-	-	-	$1.00 m	-	-	-	-	-	-
11kV Indoor SB Replace New Lynn	-	$1.80 m	-	-	-	-	-	-	-	-
11kV Indoor SB Replace Riverhead	-	-	-	$1.00 m	-	-	-	-	-	-
11kV Indoor SB Replace Sabulite	$1.80 m	-	-	-	-	-	-	-	-	-
11kV Indoor SB Retrofit	-	-	-	-	-	$0.55 m	$0.55 m	$0.55 m	$0.55 m	$0.55 m
11kV Indoor SB Retrofit Belmont	-	$0.55 m	-	-	-	-	-	-	-	-
11kV Indoor SB Retrofit Birkdale	-	-	$0.55 m	-	-	-	-	-	-	-
11kV Indoor SB Retrofit Henderson Valley	-	-	-	$0.55 m	-	-	-	-	-	-
11kV Indoor SB Retrofit Hillcrest	-	-	-	-	$0.55 m	-	-	-	-	-
33kV Indoor SB Renewal Wairau Valley	-	$5.00 m	-	-	-	-	-	-	-	-
33kV Outdoor CB Replace Belmont	-	$0.38 m	-	-	-	-	-	-	-	-
33kV Outdoor CB Replace Browns Bay	-	-	-	-	$0.31 m	-	-	-	-	-
33kV Outdoor CB Replace Helensville	-	-	$0.25 m	-	-	-	-	-	-	-
33kV Outdoor CB Replace Sabulite	-	-	-	$0.63 m	-	-	-	-	-	-
33kV Outdoor CB Replace Waikaukau	-	-	-	-	$0.31 m	-	-	-	-	-
33kV Outdoor CB Replace Wellsford	$0.25 m	-	-	-	-	-	-	-	-	-
Cable Replace	$1.70 m	$1.70 m	$1.70 m	$1.70 m	$1.70 m	$1.70 m	$1.70 m	$1.70 m	$1.70 m	$1.70 m
Crossarm Replace	$2.30 m	$2.30 m	$2.30 m	$2.30 m	$2.30 m	$2.30 m	$2.30 m	$2.30 m	$2.30 m	$2.30 m
Earthing Upgrades	$0.11 m	$0.11 m	$0.11 m	$0.11 m	$0.11 m	$0.11 m	$0.11 m	$0.11 m	$0.11 m	$0.11 m
Ground Mounted Switchgear Replace	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m	$0.25 m
Pillar and Pit Replace	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m
Pole Mounted Switchgear Replace	$0.33 m	$0.33 m	$0.33 m	$0.33 m	$0.33 m	$0.33 m	$0.33 m	$0.33 m	$0.33 m	$0.33 m
Pole Replace	$2.24 m	$2.24 m	$2.24 m	$2.24 m	$2.24 m	$2.24 m	$2.24 m	$2.24 m	$2.24 m	$2.24 m
Power Transformer Replace 33/11	-	$2.20 m	-	$2.20 m	-	$2.20 m	-	$2.20 m	-	$2.20 m
Reconducting	$0.19 m	$0.19 m	$0.19 m	$0.19 m	$0.19 m	$0.19 m	$0.19 m	$0.19 m	$0.19 m	$0.19 m
Reliability Improvements	$1.50 m	$1.50 m	$1.50 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m	$1.25 m
Strategic Spares	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m	$0.05 m
Transformer Replace	$1.55 m	$1.55 m	$1.55 m	$1.55 m	$1.55 m	$1.55 m	$1.55 m	$1.55 m	$1.55 m	$1.55 m
Zone Substation Oil Containment	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m	$1.00 m
Total	**$ 13.3 m**	**$ 21.2 m**	**$ 13.9 m**	**$ 18.4 m**	**$ 12.2 m**	**$ 17.3 m**	**$ 15.1 m**	**$ 17.3 m**	**$ 15.1 m**	**$ 17.3 m**

Table 6-34 : Proposed integrity capex - Northern

The major asset replacement programmes foreseen for the next five years are discussed below.

6.7.1 11kV Cable Replacement

These 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 cables nominated for 2010 replacement are in the circuits QUAY1, FREE9, and LIVE16.

We anticipate replacing three circuits per year in 2010, 2011 and 2012. This is expected to continue for the next ten years as other sections of cable show end-of-life failures.

Northern poly cable replacements have been historically included in the replacement programmes and have been assumed to continue at a constant rate. It is expected that this rate will fall as the population of cables of this type diminishes.

6.7.2 LV Connector Replacement Project

This project began in 2007 and involves the replacement of all existing neutral connectors. It is proposed to continue this project for another year and reassess the need to continue carrying out this replacement. For this reason a forecasted sum of $500,000 for each area has only been allocated for FY11 at this point.

6.7.3 Mushroom Pillar Replacement Project

These pillars are found in the Northern region and have been identified as hazardous. While most of these pillars have been replaced, a survey is required to more accurately determine how many of the mushroom pillars remain in service. Based on an estimate of the number of remaining pillars, it is anticipated that $900,000 will be required for year 2010 and $300,000 the year after.

6.7.4 Pole Transformer King Bolt Replacement

It has been found that crossarm king-bolts have been rusting in the section of the bolt where it is encased by the crossarm. This affects all king-bolts but in general 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-bolts are under a much heavier load and the failure of the bolt will likely lead to the transformer falling to the ground.

Replacement of king-bolts requires about as much effort as replacing the hanger arm. A retro-fit clamping support has been devised that allows the transformer arm to be supported without having to rely on the king bolt and a programme is underway.

6.7.5 Overhead Conductor Condition Replacement

This refers to aged Cu conductor. A cost of $50,000 per km and replacement lengths of 5km has been assumed, with replacement beginning in 2011 and continuing for three years. If further sections are identified, this will need to be re-evaluated.

6.7.6 Dome Valley Insulator Replacement

Failure of insulators has led to fires in the plantation forest that this line traverses. The completion of the insulator replacement programme is expected in FY11, with $420,000 anticipated investment in that year.

7. Systems and Processes

This section describes the information systems and associated business processes that Vector maintains and operates to manage its asset data.

7.1 Overall Approach to Asset Lifecycle Data

Central to Vector's approach is the establishment of a master register for all asset static data (technical asset attributes including hierarchical, spatial and contextual data) and transactional data (inspection, maintenance and defects history). A separate master repository is maintained for historical time-series data derived from numerical relays and other Intelligent Electronic Devices (IEDs). In addition, Vector employs specialised tools for network modelling, network monitoring and control, and the management of engineering drawings and other technical documents.

Note that while Vector is responsible for asset management, Vector's field services providers (FSPs) are responsible for maintaining the assets and scheduling activities and resources accordingly. Northpower and Electrix use proprietary works management systems (WASP and Workbench respectively) for this purpose. The diagram below (Figure 7-1) illustrates the information flows between Vector and its FSPs by system and activity type.

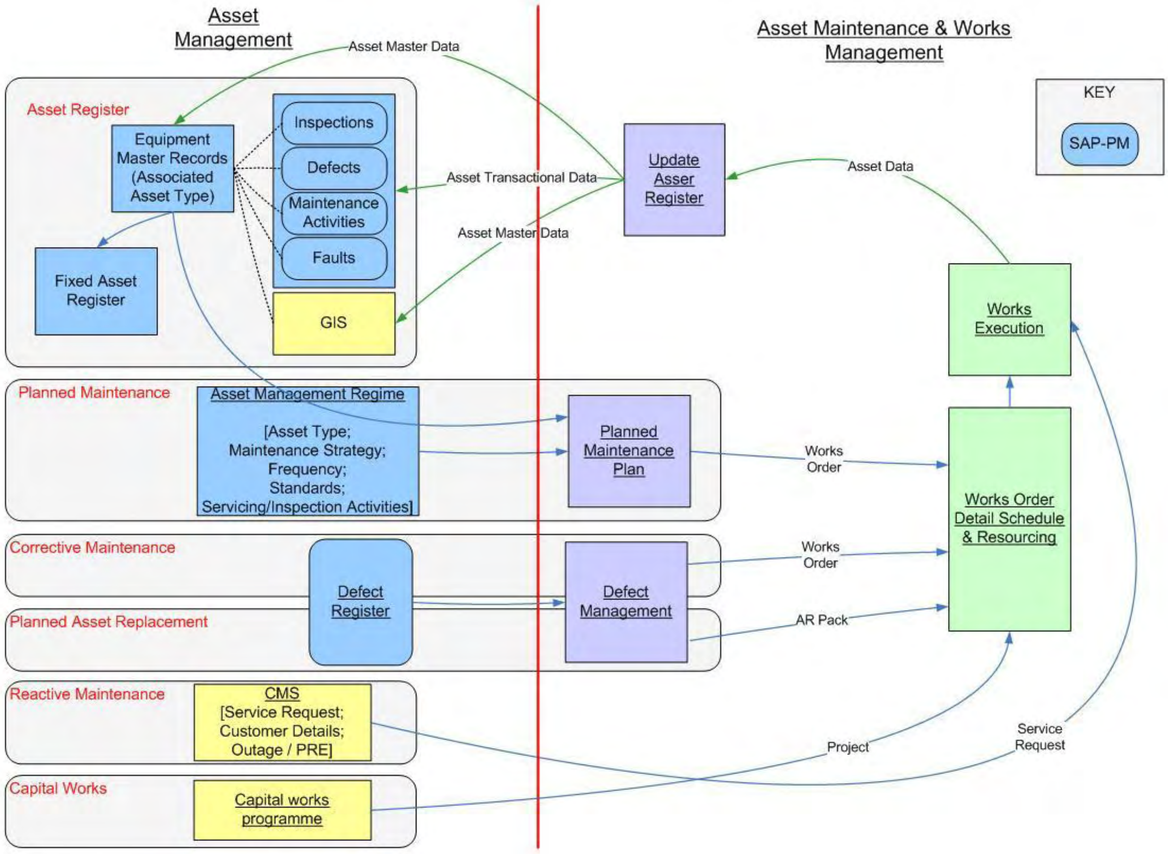


Figure 7-1 : Asset information flows between Vector and its FSPs

Some aspects of this approach represent a significant change from previous practice at Vector. Specifically, the establishment of a single Technical Asset Master (TAM) register for asset static and transactional data is being done to replace a number of discrete databases and paper-based records.

The diagram below (Figure 7-2) shows asset data flows within the present system architecture. Whilst Northpower's WASP system provides updates to Vector's Maintenance Information System (MIS), there is no linkage to Vector's SAP or GIS registers, and this represents the only instance of electronic connectivity between FSPs' repositories of asset transactional data and Vector's information systems.

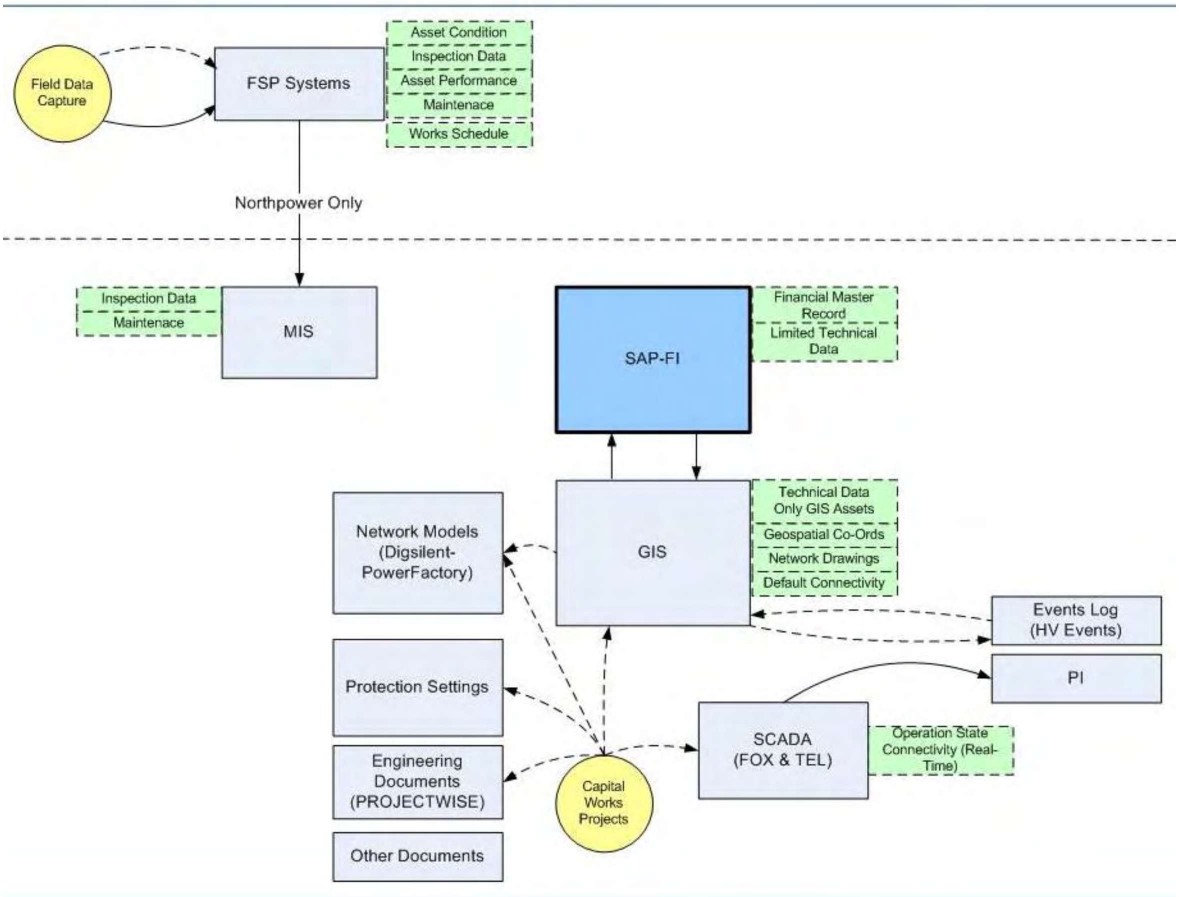


Figure 7-2 : Asset data system landscape - current state electricity distribution

The data in these standalone repositories has been assessed as incomplete, inaccessible, and difficult to report from or manipulate due to a lack of common reference tags.

The Technical Asset Master (TAM) register has been developed in Vector's Enterprise Resource Planning (ERP) system, SAP, and will be deployed to Vector's FSPs in the second quarter of 2010. The associated architecture and asset data flows are illustrated in Figure 7-3.

This initiative is designed to support Asset Investment's strategic goal of improving asset information and data quality across the business, as described in Section 1, through delivery of the following benefits:

- Improved access to asset static data and transactional data;
- Supporting regulatory compliance;
- Improved audit compliance;
- Ability to reconcile technical and financial asset registers;

- Improved development, operational and maintenance planning efficiency and effectiveness;
- Improved investment decisions (optimised operational expenditure (opex)/capital expenditure (capex));
- Accurate network asset valuation;
- More efficient asset creation process (earlier settlement of WIP);
- Ability to create technical asset records via the procurement process; and
- Improved oversight of works management.

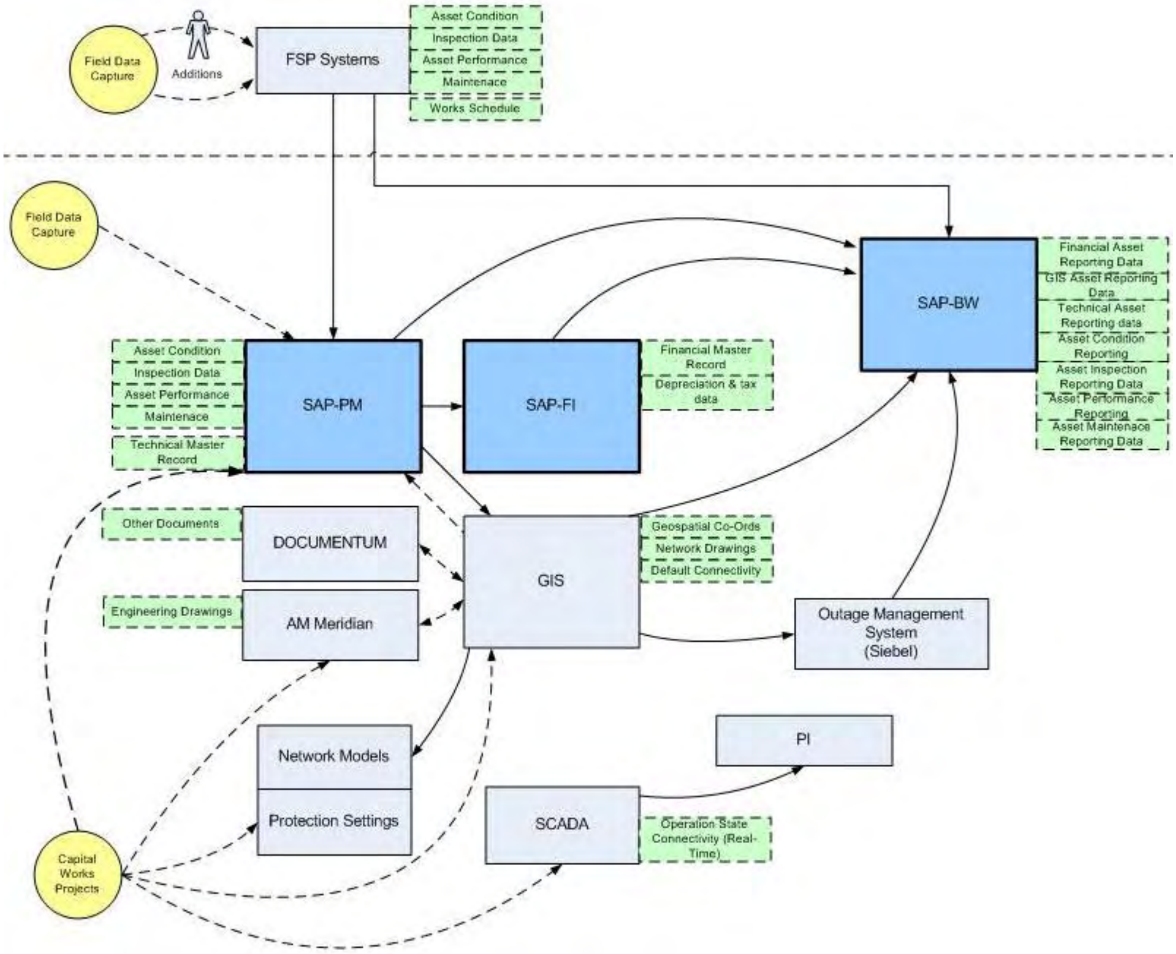


Figure 7-3 : Asset data landscape - future state gas and electricity

7.2 Asset Data Quality

By developing a complete and accessible repository for asset static and transactional data, in a common format, with visibility across the data sets, the TAM gives Vector the ability to implement an enhanced asset data quality programme for these data sets.

Improvement actions are currently being prioritised across all asset management data sets, comprising static asset attribute data, transactional data (inspection, maintenance and defect records), time-series data and engineering information.

Current data quality and security limitations for these data sets have been quantified by assessment in terms of the current condition (in quality and security terms) and criticality of the data (defined in terms of sensitivity and availability). A series of initiatives, including the TAM project, is in train to address these limitations, as described at the end of this section.

7.3 Asset Information Systems

7.3.1 Technical Asset Master

Vector has developed a Technical Asset Master (TAM) register in SAP-PM (Plant Maintenance) to provide a complete inventory of all network physical assets, including strategic spares.

The purpose of the TAM is to be the master record of all static information (attributes or characteristics) about Vector's network physical assets, with the exception of geospatial information and connectivity.

The structure of SAP-PM has been configured to interface with Vector's Geospatial Information System (GIS) and potentially to the FSPs' works management systems via a middleware layer. SAP internal linkages are enabled with SAP-MM (Materials Management), to facilitate efficient processes for asset creation and refurbishment, and with the financial fixed assets register in SAP-FI (Financial Information) as shown in the diagram below (Figure 7-4).

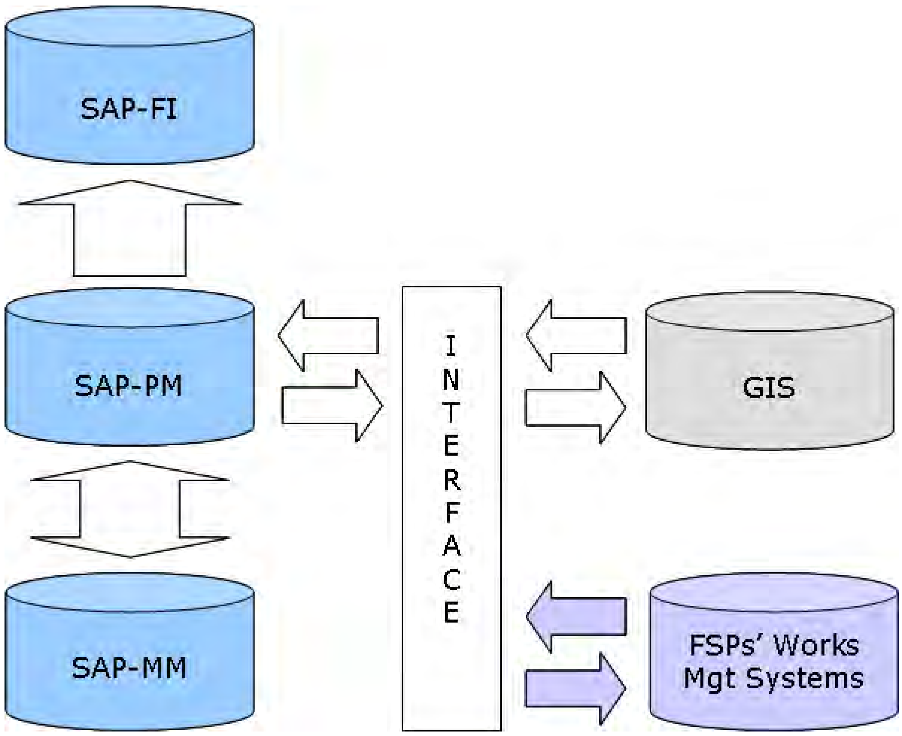


Figure 7-4 : TAM overview

7.3.1.1 TAM Systems and Interfaces

In line with the objective of optimising our lifecycle asset management capability, the SAP-PM system and associated business processes have been designed to hold the planned maintenance regime for each asset, according to the relevant engineering standard, and to capture transactional information against each asset record, including inspection activities, maintenance activities and defects.

On deployment of the TAM the data will be updated continuously by Vector's FSPs, in line with the service level agreements (SLAs) for asset data which will be extended to include SAP-PM. Business processes have been developed and agreed with the FSPs to manage the creating, updating and deleting of network asset records.

7.3.2 Customer Management System (CMS)

Vector uses Oracle's Siebel application for its CMS. A full record of network faults is captured by Vector's FSPs in Siebel. This includes certain asset-related technical information as well as the operational and customer information more conventionally associated with CMSs. Therefore, 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 asset record in SAP-PM will include reference to the corresponding CMS service log number.

7.3.3 Maintenance Information System (MIS)

Vector's MIS has been retired and is superseded by the TAM. Transactional information provided by the FSPs to SAP-PM is defined by Vector's engineering standards, including maintenance standards which have been updated to reflect the new data requirements. Data provision is by direct input into SAP-PM or potentially via an interface, using the same middleware layer as the GIS interface.

Works management is enabled by deriving inspection and maintenance schedules from the information held in SAP-PM, in line with Vector's operational and engineering standards and supported by Vector's asset specialists.

7.3.4 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 mapped into Smallworld GIS. The model is continually updated by GIS specialists within Vector's FSPs. This acts as the master register for asset geospatial information and default network connectivity.

Analysis and thematic mapping of the information in our GIS is facilitated by exporting base data into ArcGIS and 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.

7.3.5 Fixed Asset Register (FAR)

We maintain a register of our financial fixed network assets (FAR) in SAP-FI (Financial Information). The FAR provides the basis for depreciation, taxation, valuation and financial reporting, and is currently reconciled on a monthly basis with TAM data. The FAR is continuously updated by the master data held in the TAM.

7.3.6 Asset Data Reporting

Reports can be created out of each of the SAP modules (PM, MM and FI) and GIS. Additionally, Vector uses the SAP-BW (Business Warehouse) tool and a suite of information visualisation tools, including spatial mapping, to facilitate holistic reporting and analysis of asset management data, including that held in other systems, for example CMS.

7.3.7 Asset Classification Data Flows

In order to support consistency between the component parts of Vector's asset management system, classification data is strictly controlled and maintained as shown in the following diagram (Figure 7-5).

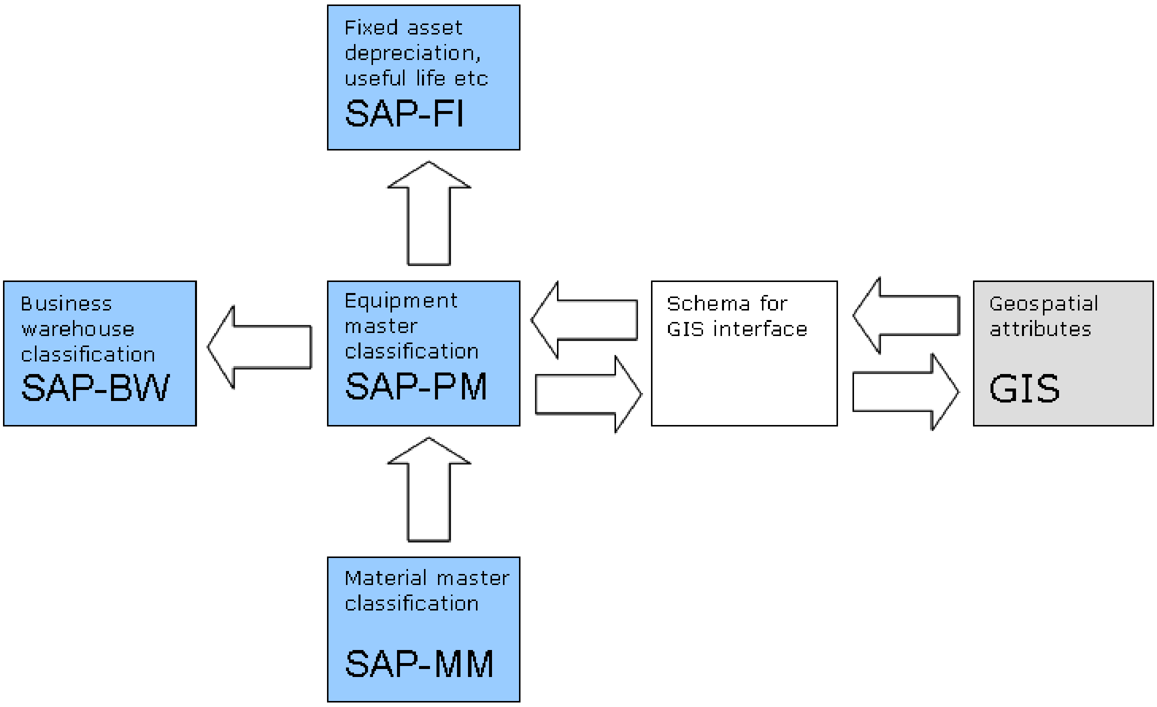


Figure 7-5 : Asset data flow

7.3.8 Network Valuation Model

Vector's network asset valuation for financial reporting purposes and Commerce Commission disclosure purposes is derived from the asset data maintained in the FAR, TAM and GIS.

7.3.9 Time-Series Data

A very large archive database of historical time-series data is maintained in an OPC (Object linking and embedding for Process Control) formatted repository, PI, which captures data transmitted across the SCADA system from several hundred Intelligent Electronic Devices (IEDs) located at zone substations and other key points around the electricity network. 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 PI.

A proposed upgrade of the PI system will enable advanced calculations to be performed practically in real-time, and transmittal of notifications to FSPs and others, either directly, or via SAP-PM. More generally, by combining time-series data with the TAM data in SAP-PM, Vector's ability to execute condition-based/risk-based asset maintenance strategies will be enhanced.

7.3.10 Network Events Log

A replica of Vector's high voltage and medium voltage network structure is maintained in a bespoke system, HV Events, to manage the recording of interruption events and to prioritise network reconfiguration and restoration after an event.

The system has recently been upgraded to identify events by individual distribution transformer. This enables the number of customers affected and the duration of interruptions to be identified against each event, by event type and location.

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.

A future development is planned in which time-series data (indicative of asset condition) and events/faults statistics can be blended with asset static data to provide the basis for enhanced condition based maintenance, and to define specific operational initiatives.

7.3.11 Network Modelling Software

Vector's high voltage and medium voltage electricity networks are modelled with DIgSILENT PowerFactory software. We also operate the StationWare application for the management of our system protection settings. This enables us 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.

We are in the process of upgrading our model in line with IEC61850 and Vector's technical requirements for protection and control, to facilitate enhanced reliability and security analysis.

Once the current upgrades are complete, it is planned to enable the network model to be updated via an interface from GIS and ultimately to develop its use together with the protection setting tool for operational applications.

7.3.12 Network Monitoring and Control

Vector's electricity network is monitored and controlled in real time using the SCADA system (refer to Section 2.3.5).

7.3.13 Customer Connections

Vector maintains a database of all Installation Control Points (ICPs) in the Gentrack system, which is linked to its GIS and Interruption Events systems and the Metering and Reconciliation Industry Agreement (MARIA) electricity industry connections register.

7.3.14 Technical Document Management

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.

7.4 Initiatives to Improve Data Quality (Accuracy/Completeness)

The following table summarises the current practice for the key data handling process, the desirable practice and the target dates for achieving potential enhancements.

Data Set	Current Practice	Desired Practice	Completion Date
Asset identification	Unique ID numbers in GIS for all geospatial assets and FAR for all significant assets	Unique ID numbers in GIS and Technical Asset Register (TAM) for all assets	2010
Asset classification	Hierarchical network asset structure in place (in GIS) Financial asset classification for depreciation purposes (in FAR)	1:1 relationship between GIS and TAM and clearly defined relationship between TAM and FAR	2010
Asset serial number	Recorded in GIS	Recorded in TAM	2010
Asset technical attributes	Attributes recorded in GIS, project files and FAR	Master data for all key asset attributes established in TAM	2010
Asset geospatial coordinates	Coordinates recorded in GIS	Coordinates recorded in GIS	2010
Asset financial data	Recorded in FAR	Recorded in FAR	2010
Asset valuation	Derived from data in FAR and GIS	Derived from TAM	2010
Historical asset performance, condition, inspection and maintenance data	Recorded in Vector's field service providers' maintenance information systems	Critical data fields recorded in TAM	2010

Data Set	Current Practice	Desired Practice	Completion Date
Past and predicted future asset lifecycle costs	Derived from MIS and network modeling	Derived from TAM and network modeling	2010
Network connectivity	In network diagrams	Dynamically linked to network model and GIS	2012
Network reliability information	Recorded in bespoke database with most faults data also recorded in GIS	Upgraded database interfaced with TAM and GIS	2011
Network security information	Derived from network model	Derived from enhanced network model	2011

Table 7-1 : Initiatives to improve data quality

8. Risk Management

8.1 Risk Management Policies

Risk management is integral to Vector's asset management process. Vector's intention is to further embed risk management into all significant processes in such a way that they are more effective and efficient. 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, compliant with the ISO31000 standard and implement those practices in a manner appropriate to a leading New Zealand (NZ) publicly listed company that supplies critical infrastructure to NZ communities 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 is also underpinning Vector's ability to meet its compliance obligations.

This capability is built on implementing a risk management framework which allows risks to the business to be effectively identified and assessed. From these insights, risks are appropriately managed through a series of controls or mitigated to an appropriate risk level. The effectiveness of the controls is monitored on an ongoing basis.

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 as part of the asset management process. The controls or mitigation measures often serve to define the need for investment or work practice decisions, while the impact of the risk being addressed determines the priority of such investments.

The acceptable level of asset-risk will differ depending on the impact, should an asset fail, on the electricity supply. 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 will 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 Board Risk and Assurance Committee

Vector's Board has overall accountability for risk management at Vector. This responsibility has been delegated to the Board Risk and Assurance Committee (BRAC) which provides oversight of Vector's risk and assurance.

The BRAC meets at least four times a year to review the group's risk context, key risks and key controls, which include the internal audit and insurance programmes.

The management of the electricity business network and its assets is also subject to this review.

8.2.2 Executive Risk and Assurance Committee

The executive management team has established an Executive Risk and Assurance Committee (ERAC) to provide special specific focus and leadership on risk management within Vector. The committee has the overarching responsibility of ensuring that 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, when it reviews risk management policy and its implementation, as well as key risks.

8.2.3 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 owned by 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 group also manages the safe and reliable operation of the network to predefined levels.

8.2.4 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.

8.2.5 Risk and Assurance Manager

The Vector Risk and Assurance Manager is responsible for the development of an approved risk management framework, which includes a risk management plan outlining the approach, management components and resources applied to risk management.

The role includes the monitoring and reporting of progress against this plan and overall delivery of risk management and assurance across the group, as well as communicating on risk management and assurance issues across Vector.

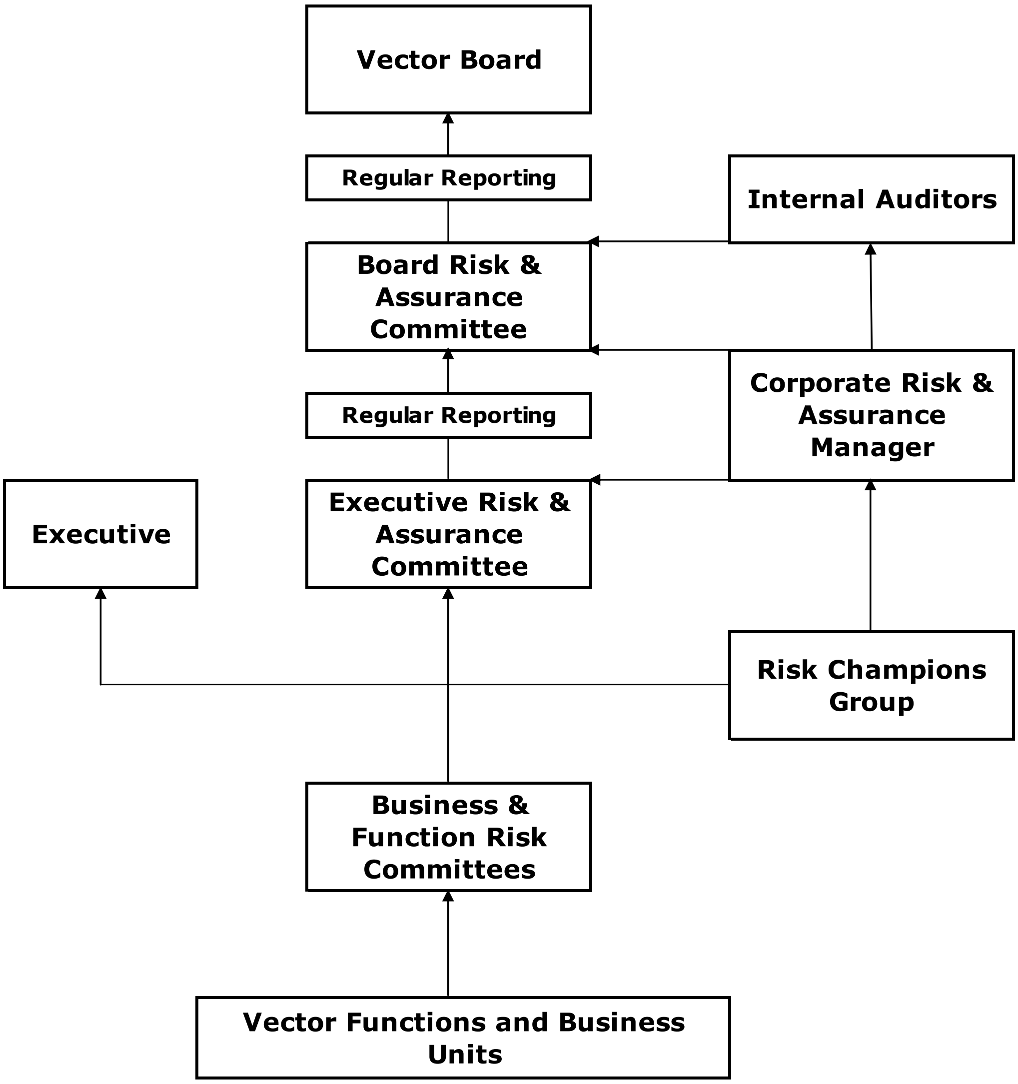
8.2.6 Staff

Each staff member is responsible for ensuring they understand risk management practice in Vector and how it applies to them and their business activities and processes. This includes adopting an appropriate risk management awareness and implementation approach. All staff are actively engaged in the identification of new risks and controls, and ensuring these are appropriately acknowledged.

Individual staff may have specific responsibilities for the ownership and management of a specific risk, control or treatment.

8.2.7 Vector Risk Structure

Figure 8-1 shows Vector's risk management structure and reporting lines.



Arrows indicate reporting lines

Figure 8-1 : Vector's risk management structure

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 as it standard, having developed its policy and framework using the superseded AS/NZS 4360:2004.

The risk management process adopted by Vector is shown in Figure 8-2 below.

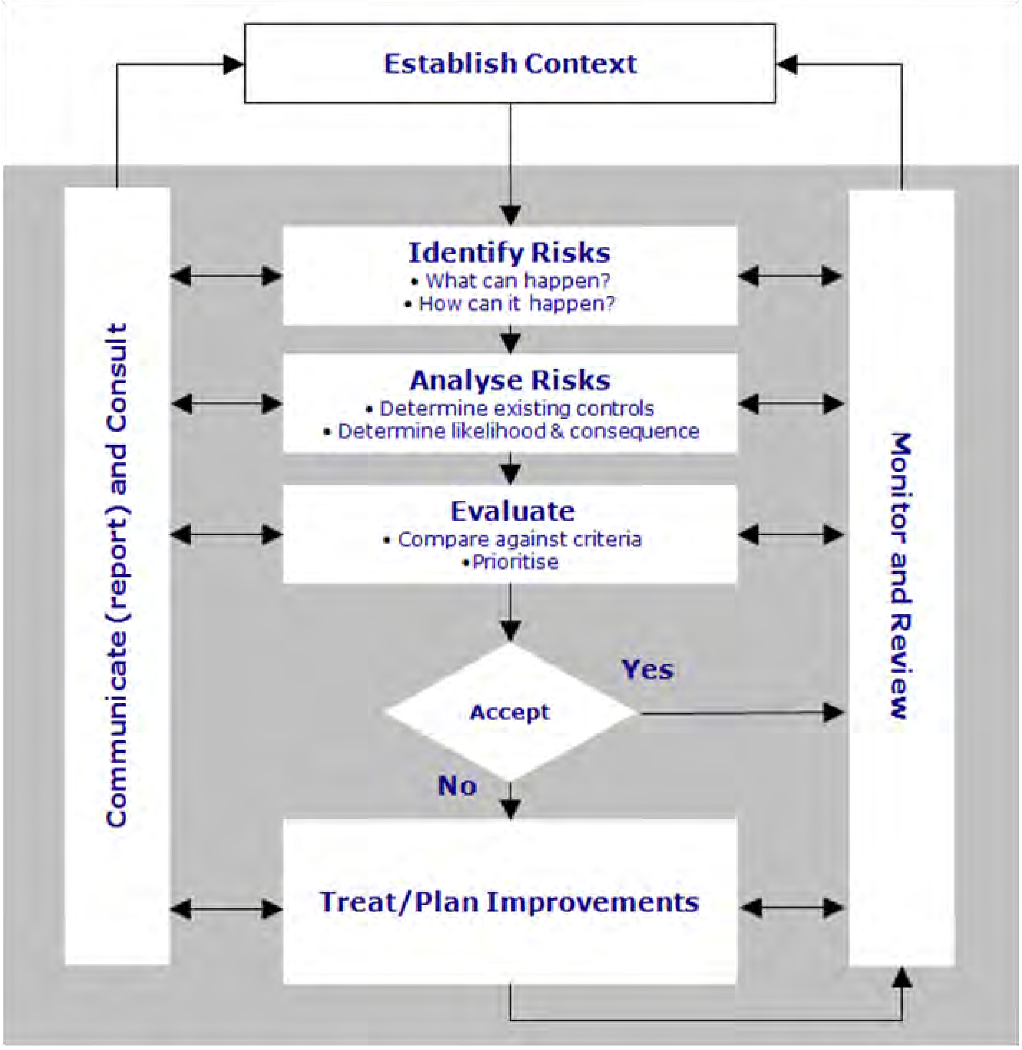


Figure 8-2 : Vector's risk management process (based on ISO31000: 2009)

The level of risk is determined on the basis of "likelihood" and "consequences" of the event associated with the risk occurring. The combination of these two criteria is used to prioritise the level of controls to manage the risk. The risk assessment matrix adopted by Vector is shown in Figure 8-3 below.

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

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 the company reputation.

Vector has controls in place to manage key risks and has internal review processes associated with these controls. At the highest level is Vector's internal audit programme which provides assurance around these controls. This programme is overseen by the BRAC.

Risk management practice is reviewed periodically by independent third parties as part of this overall assurance programme. Issues are noted and responses developed and implemented by management. The results of the audit, management responses and delivery of actions are reported through to the BRAC.

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 group also manages the safe and reliable operation of the network to predefined levels.

Both the AI and SD groups have an integrated approach to risk management and their respective responsibilities in relation to it.

This encompasses:

- Identifying and assessing risks;
- Managing and maintaining controls;
- Developing and implementing treatments proportionate to 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 the organisation, 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 (i.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 at a cost proportionate to the benefit gained. These risks are managed at various levels, as appropriate, within the business. 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 how specific or high a risk is
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 managed 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	Where risk came from in terms of past register / or noted as new
	Date listed	Date when added to new register once risk was known
	Reviewer	Name of person who reviewed risk
	Last updated	Date when risk overall has last been reviewed

Table 8-1 : Risk register headings

8.3.2.2 Key Operational Risks

The table below outlines the most significant electricity risks that Vector has identified in its asset management risk profile. While control and mitigation measures are in place to address these to varying degrees, work is ongoing to improve the controls or to ensure that they remain effective.

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
AIAE5006	An asset or the way we operate the business exposes staff, contactors and the public to various forms and levels of risk. If a risk eventuates it could lead to a health concern, injury or death of anyone of those parties leading also to costs, liabilities/penalties and potential regulation.	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 satisfaction 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 reputational, customer satisfaction and potential regulatory outcomes.	Very High	High	High
AIAE5002	An asset or the way we operate 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

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
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 increased regulatory attention.	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	High	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	High	Low
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	Moderate
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.	High	High	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 increase in cost.	High	High	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	Very High	High	Moderate

Risk ID	Risk description	Risk Assessment Classification		
		Absolute	Controlled	Treated
	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.			
AIPI0004	Inadequate utilisation (load profile) information. High capital and operating costs resulting from inability to optimise asset utilisation	High	High	Low
AIPI0011	Breach of Commerce Act (Electricity Distribution Default Price Quality Path) Determination 2010. Serious breaches of the quality path.	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 is in the process of enhancing the integration of the risk management process into its core planning and prioritisation activities. Section 6.3 outlines the activities underway to integrate the network development planning and the risk management processes. It is recognised that many of the risk control or mitigation measures require capital investments, and that capital investment is largely driven by risk-associated factors.

Risk-assessments and treatments will form an important input into a computer-based project prioritisation system being developed by Vector. Conversely, the outputs from the network development plan will feed into the risk management system and influence the controlled rankings of risks.

It is also intended to develop an overall risk-score which will be tracked over time, to measure and report on the effectiveness of risk-management (and specifically asset-related risk management) at Vector.

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 the end of 2010.

8.3.2.4 Incident Management and Reporting

Vector recognises that the effective and efficient management and reporting of incidents is a major component of the risk management process, particularly in delivering on its health and safety policy and objectives. 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:

- Manage and stabilise the situation. This includes ensuring the safety of its employees, contractors and members of the public;
- Notify the appropriate internal staff and external authorities, agencies and organisations of the incident;

- Investigate the incident and prepare an incident report that considers all of the contributing factors, identifies the root cause and recommends remedial actions as appropriate;
- Carry out any remedial actions; and
- Close out the incident.

The objectives of incident investigations are to:

- Analyse, determine and document the root causes of the more significant incidents;
- Identify, track, and implement the corrective actions required to reduce the likelihood of recurrence of incidents;
- As appropriate, trend the root cause data from these incidents to identify system problems that, when corrected, can lead to increased improvements in performance;
- Inform management when problems are encountered to allow prompt attention to the incident;
- Document immediate corrective actions that are taken; and
- Provide data to help determine where problems are occurring, where resources need to be applied, and how performance is changing.

Vector has recently reviewed its incident reporting processes and has implemented enhancements including ensuring that there is greater consistency in weekly reporting of significant incidents across the business.

A team has been established to identify the business 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;
- 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's Business Continuity Management (BCM) policy requires Vector, following a range of possible events, emergencies and crises, to:

- Minimise impact on people, operations, assets and reputation;
- Maintain services to the fullest possible extent; and
- Recover to a business as usual position.

Vector requires this in order to meet:

- Stakeholders' expectations in terms of protecting value if a disruptive event occurs; and
- 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).

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 that 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 that it has:
    - Appropriate BCM communication/awareness processes in place;
    - Appropriate levels of BCM training; and
    - Appropriate 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;
- The BCP is developed by those who are associated with the activity and who are named in the plan;
- It is reviewed annually and fully reviewed within a timeframe appropriate to the associated activity, or when required if significant external or internal changes occur;
- It has a programme for testing the combination of:
  - People;
  - Plan;
  - Infrastructure, and
- It has an appropriate associated training and communication plan.

With respect to components, each plan:

- 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 must also have plans regarding how it will function during and after an emergency and is also required to participate in the development of CDEM strategy and plans.

Vector has a number of continuity plans in place as well as an overall Crisis Plan.

Vector is also a member of the Auckland Engineering Lifelines Group (AELG) and through this membership keeps abreast of developments in the CDEM area to ensure it is fully prepared for emergencies arising from identified threats including volcanic eruption, tsunami, earthquake, tropical cyclones and storms.

Vector is also a member of the National Engineering Lifelines Committee and keeps abreast of national issues and initiatives through this forum.

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.

8.5 Risk Mitigation Measures

8.5.1 Treatments and Controls

The first line of response to or protection against risks is provided through Vector's risk management system and through the use of the treatments or controls identified to address or mitigate against known risks. This is as described in Section 8.3 above.

8.5.2 BCM 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;
- Major Incident Plan;
- Switching Plans;
- Storm Response Plan;
- Electricity Operations Centre Emergency Evacuation Plan;
- Emergency Load Shedding Plan;
- Participant Outage Plan;
- Vector Group Emergency Communications Plan;
- Vector Group Pandemic Health Plan;
- Transpower Contingency Plans;
- Call Centre Business Continuity Plan; and
- Spill response protocol for transformers, switchgear and fluid-filled cables.

These plans are further described below.

8.5.2.1 Crisis Management Plan

The Crisis Management 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 on the company. It is designed to establish clear lines of communication and reporting, as well as action guidelines for the Vector group.

While the Crisis Management Plan procedures have been developed to cover a broad set of circumstances, Vector is mindful that every crisis throws up its own unique set of circumstances, which will require good judgement from Vector employees to be managed ably.

The Crisis Management 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.

8.5.2.2 Major Incident Plan

The purpose of the Major Incident Plan is to ensure that 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 major incident 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 on at least annually.

8.5.2.3 Switching Plans

For all major feeders, the network is designed to allow reconfiguration by switching so that 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 restores 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 at least once a year.

8.5.2.4 Storm Response Plan

The purpose of this plan is to ensure Vector is prepared for, and responds to, any storm or potential storm that may impact on the electricity networks. The plan ensures our response is appropriate, effective and undertaken in a planned manner whilst ensuring compliance with industry codes and regulations. The plan describes the actions required and the responsibilities of staff during a storm emergency and focuses on continuously improving systems and communications (internal and external) to benefit customers and retailers.

The plan is structured to ensure the establishment and maintenance of effective communications between all parties involved in the maintenance and restoration of electricity supply, and ensures the preparedness and availability of all required Vector resources during an event.

8.5.2.5 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, west of Auckland. Regular evacuation exercises are held to ensure that evacuation of the control centre can proceed at any time.

8.5.2.6 Emergency Load Shedding Strategy

The purpose of this document is to provide procedures for emergency load shedding when required, as requested 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 Governance Rules 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 will be requested by Transpower, acting in the capacity of System operator, to shed load to avoid cascade tripping of the grid under emergency situations. Vector has assigned load groups to cover such contingencies.

8.5.2.7 Participant Outage Plan

As a result of the Electricity Governance (Security of Supply) Regulations 2008, the Electricity Commission 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 Commission;
- Comply with requirements of the Electricity Commission's Security of Supply Outage Plan (SOSOP);
- Comply with Electricity Governance (Security of Supply) Regulations 2008; and
- Supplement the Electricity Commission's Security of Supply Outage Plan.

8.5.2.8 Vector Group Emergency Communications Plan

In any emergency, crisis or business continuity event affecting Vector, public perceptions will be influenced by the way in which the company responds to issues arising from the event and how it communicates with stakeholders.

This communications 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.

By having a consistent, robust and scalable approach to our communications – regardless of the severity of an incident – Vector can minimise company reputation damage risk by properly managing relationships and maintaining public confidence by demonstrating our capabilities in challenging circumstances.

8.5.2.9 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.

8.5.2.10 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 network north of Otahuhu. Some Transpower GXPs have more than one busbar so supply lost could be to a single bus or to a whole substation.

8.5.2.11 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 this document is to assess the potential risks and planned workarounds for those risks in order that Telnet 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.

8.5.2.12 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.

8.5.2.13 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.

8.5.2.14 Insurance

The Treasury function manages the placement of insurance for the company.

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 Policies

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 all our people, contractors, the public and visitors in our work environment. The company is committed to continual and progressive improvement in its health and safety performance and will ensure that 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 & Safety Policy.

Vector's Health & Safety Policy is 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 will:

- As a minimum, meet all relevant legislation, standards and codes of practice for the management of health and safety;
- Identify, assess and control workplace hazards;
- Accurately report, record and learn from all incidents and near misses;

- Establish health and safety goals at all levels within the Company, and regularly monitor and review the effectiveness of our Health and Safety Management System;
- Consult, support and encourage participation from our people on issues that have the potential to affect their health and safety;
- Promote our leaders', employees' and contractors' understanding of the health and safety responsibilities relevant to their roles;
- Provide information and advice on the safe and responsible use of our products and services;
- Suspend activities if safety would be compromised; and
- Take 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 other's 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.

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 & 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 ALARP, so as to ensure the safety and health of personnel, the public, the environment and plant in the planning and design of new build, enhancement and replacement of its network;
- Safety & health hazards, as well as the risks associated with operations, activities, and assets, are identified and managed to an acceptable level;
- 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 that the reliability of critical safety back up equipment, protective devices and key operating equipment is maintained;
- Safety considerations are built into our design standards and asset selection criteria;
- Appropriate safety equipment is installed, inspected and maintained and it is ensured that all staff are competent to identify equipment in need of repair or replacement;
- All FSPs working for the company are required, as a minimum, to comply with the Vector 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 staff/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 carried out. 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 (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's easy to get in touch with us we have dedicated free phone numbers;
    - Vector is also a founding member of the "beforeudig service" (www.beforeudig.co.nz). "Beforeudig" 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 national 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. In November 2009, over 700 staff from Vector, Treescape, Electrix and Northpower attended the Vector Safety day.

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 Energy Safety Review Bill

The new Energy Safety Review Bill is to be circulated to the industry by March 2010. A key change for asset owners within the gas and electricity industries will be the requirement to operate a safety management system for public safety and 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 our first audit in approximately two years time.

8.7 Environmental Management

8.7.1 Environmental Policy

Vector's environmental policy confirms its commitment to managing the environmental impact of its businesses, taking account of legislation and standards. The company conducts its operations in such a way as to respect and protect the natural environment, 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 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; and
- Communicate with employees, contractors, customers and other relevant stakeholders on environmental matters.

To achieve this Vector will:

- Plan to avoid, remedy or mitigate any adverse environment effects of our operations; and
- Focus 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 our 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. Our key practices in this regard include the following:

- Vector continually explores opportunities for minimising waste generation and, when identified, pursues economically viable opportunities that are 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 Group's key performance indicators KPIs) is to avoid any activity that would cause the group to be in breach of the Resource Management Act;
- 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 learning's and improvements shared across our FSPs at the safety leadership forum.

9. Expenditure Forecast and Reconciliation

This section summarises how the capital, operating and maintenance expenditures are compiled, including prioritisation of projects. The forecast for the 2011 financial year and the subsequent years through to 2020 are also presented.

As Vector operates to a June financial year all our budgeting, financial and management reporting activities align with the June year. However, the Information Disclosure Requirements 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 AMP compared to the budget Vector operates to and figures that may be reported in our financial statements or elsewhere.

Due to the difference between the regulatory calendar and Vector's corporate planning cycle the Board has not yet approved the 2010/11 budgets and the 2011 forecasts are therefore still subject to change. 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 feasible that 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 asset management practices, Vector would necessarily wish to review its expenditure plans to ensure that 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 financial years ending 31 March each year from 2011 to 2020 is set out in Table 9-2. This is our forecast of the expenditure that would be required to achieve Vector's customer, network and business goals and execute the asset management activities described in this AMP.

While these estimates have been prepared based on the best information at Vector's disposal, it should be noted that electricity lines companies are experiencing a period of significant economic volatility and operational uncertainty. Factors that may materially influence investments levels going forward include:

- Economic cycles and the impact of these on electricity demand. At the time of preparing the previous AMP, a major economic slowdown was anticipated in New Zealand. While this has to some degree eventuated, it did not result in the anticipated electricity demand slowdown. There are now signs of an economic recovery, which may result in accelerated demand growth. However, based on our recent experience, the present correlation between economic cycles and electricity demand appears to be weaker than in the past, so the impact that the recovery will have on the network is uncertain. (The extent and strength of the recovery is also not clear at this stage);

- In the short term, the Government has launched an infrastructure programme that brought forward a number of construction projects. This is requiring us to initiate some major network projects (for example to supply the Waterview tunnel and the Victoria viaduct tunnel) and gives rise to substantial services relocation projects. In addition, these projects are also putting pressure on available construction capacity in the region;

- After a long period of relative stability, electricity distribution technology is now undergoing rapid change (see discussions in Sections 1 and 3). New applications are arising that are likely to have a substantial impact on how networks develop in future, and hence also on the associated expenditure patterns;
- The requirement for the Commission to set input methodologies was introduced in the 2008 reforms of the regulatory provisions of the Commerce Act. The reforms to the Commerce Act were intended to address concerns with regulatory instability and uncertainty. The reforms emphasised the importance of the Commission providing both certainty and incentives to invest, however, there are some aspects of the Commission's preliminary views on input methodologies that would run counter to those objectives. However, at this point in time, significant regulatory uncertainty remains, especially around the pricing input methodologies and the upcoming default price path reset. The Commission is currently consulting on "input methodologies" under Part 4 of the Commerce Act. These input methodologies (covering such matters as WACC and asset valuation) will establish the core drivers of Vector's future financial performance. Accordingly, actual future expenditures may be significantly impacted by the nature of the outcomes of the current regulatory regime review and up-coming price setting processes;
- It is not clear whether in future regulatory incentives and/or customer expectations will support investment in reliability improvements. The Commission has indicated that it may implement regulatory mechanisms to incentivise quality of supply improvements in future. These incentives will be essential to promote investments that will deliver any rebalance of the price-quality trade-off demanded by consumers. In the absence of such incentives, investment will only meet the current regulatory requirement to maintain network performance and quality of supply at its historical levels; and
- A key element of the regulatory regime is the basis of establishing the value of the regulatory asset base (RAB). While this is one of the input methodologies that the Commission is currently consulting on, it is concerning that their current preference appears to be for the opening RAB to be determined based on the currently disclosed RAB (i.e. the 2004 Optimised Deprival Valuation (ODV) indexed forward at CPI). Vector's preferred option is to use a fresh ODV (circa 2010), that would reflect the asset value expected from a workably competitive market, to set the starting RAB for this new regulatory regime. Vector considers that valuing the opening RAB at ODV, which reflects the value of assets that would be employed by a hypothetical efficient new entrant to the market, is the theoretically correct starting RAB value for the new regulatory regime. The three principle effects of a new ODV are to reflect changes in input prices, over and above CPI, since the last ODV, allow adjustment for any errors in or improvements to the previous ODV and to allow for a reassessment of the optimisation – reflecting critical factors such as the continuing strong growth in demand referred to above. Valuing the starting RAB using a 2010 ODV would also be consistent with past regulatory decisions as under the previous threshold regime a new ODV was to be undertaken in 2008, but this has not eventuated. The propensity for the Commission to fundamentally change its approach breaches regulatory best practice and introduces significant uncertainty into the likely future shape of the regime. This regulatory uncertainty has a significant dampening effect on the willingness to invest and, accordingly, may cause Vector to deviate from the investment levels indicated in this plan.

To accurately accommodate this level of uncertainty in a ten year investment program presents considerable difficulties. To reflect this, Vector forecasts an upper and a lower expenditure level as shown in Figure 9-1[39].

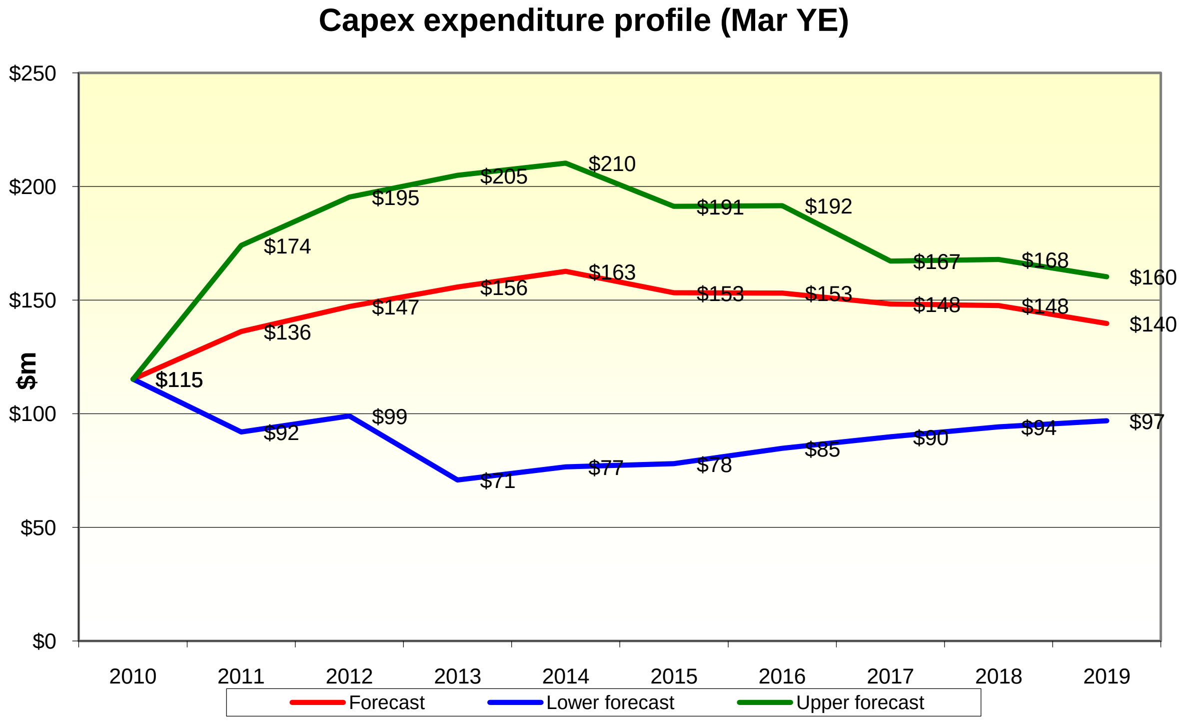


Figure 9-1 : Forecast capital expenditure range

The lower line represents minimum expenditure that Vector must commit in order to comply with its legal obligations, deal with known health, safety and environmental issues, and provide sufficient network capacity to just meet peak demands under normal conditions, but without necessarily maintaining security of supply under fault conditions.

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. The currently committed undergrounding programme is assumed to continue.

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. This will manifest as 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 our assets which will not only lead to deteriorating network performance but will also defer expenditure until a very substantial replacement requirement arises in the medium term future. Vector would therefore be very reluctant to embark on this profile and will only do so if excessive uncertainty and risks around achieving an acceptable return on investment dictate that this is the rational course of action.

[39] This expenditure range differs from that set out in the 2009 AMP to reflect the factors discussed in Section 9.3.

The upper line represents expenditure levels that would allow us 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;
- Accelerate asset replacement rates to improve age profiles;
- Underground selected parts of the network where external interference is currently impacting on reliability[40];
- Substantially reduce maintenance expenditure;
- Invest in a relatively rapid roll-out of smart network technology (as discussed in Section 3); and
- Significantly enhance network security of supply performance.

9.1.2 Maintenance and Operations

Vector's forecast maintenance expenditure for the 2011 financial year and the expenditure forecast to 2020 are listed in Table 9-2.

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 .

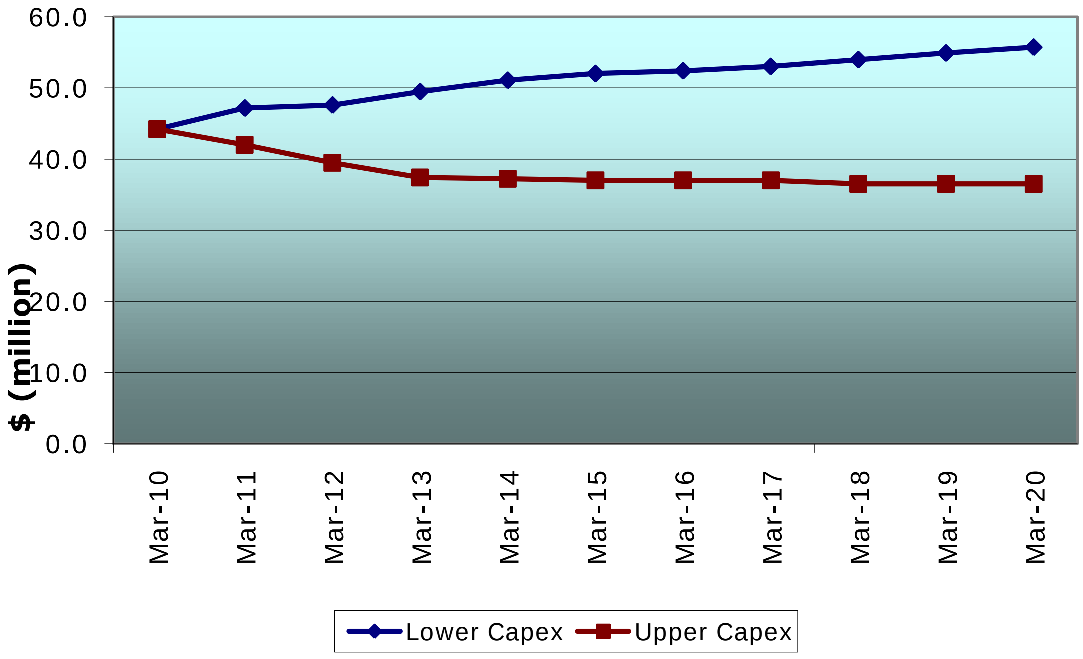


Figure 9-2 : Forecast maintenance expenditure range

[40] Vector has an ongoing undergrounding program, but the scope of this is based on meeting the AECT Trust Deed obligations. For more discretionary undergrounding, 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.

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 will 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 well as maintenance costs. There will also be a reduced requirement for renewal maintenance.

9.2 Prioritisation of Expenditure

Section 5 of this AMP details the planning policies and standards, industry information, grid and grid exit point information, load growth data, asset capacities, network operations information and network data required for the preparation of a ten year network development plan. Based on the network development plan, a ten year expenditure projection on customer and growth works programme has been prepared (refer Section 5.8).

Section 6 of this Asset Management Plan details the asset inspection, maintenance, replacement and refurbishment policies and standards. Based on these policies and standards, taking into account the information on asset age and condition and unit rates (material and labour), a replacement and refurbishment programme has been prepared for each asset category. Following from this works programme, a ten year capital and operating expenditure projection on maintenance and replacement has been prepared.

Similarly a programme for undergrounding 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 received from roading and local authorities.

An appropriate prioritisation process has been developed and implemented to ensure only those projects of the highest importance and with the highest cost-benefit are implemented. A five 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 prioritisation process includes assigning a score to each of the projects based on an understanding of the purpose, value and risk of the project. The projects are ranked according to the scores, with a ranking of one being the highest priority.

	Growth	Integrity	Customer	Legal, Regulations	H&S, Risk, Environmental	Financial & Others	Operational Improvements
1	• Capacity breach leading to asset damage	• Reactive replacement – critical assets		• Legal breach • Breach technical regulations • Regulatory breach	• Direct, serious safety threats • Direct serious environmental threats • Mitigation of extreme and very high risks • Critical cyber security breach	• Overhead Improvement Programme	
2	• Capacity breach	• Asset condition 1 - severe deterioration of asset, high risk and high consequence of asset failure	• Contractual obligations • Relocations • New connections (NPV>0) • Capacity increase (NPV>0) • Customer funded projects	• Regulatory compliance & improvement	• Anticipated serious safety threat • Anticipated serious environmental threats • Mitigation of high direct risks • Serious cyber security breach	• Avoiding financial bleeding on assets	• IT & information support critical for AI ops
3	• Security of supply breach • Network efficiency enhancement	• Asset condition 2 - asset at the end of technical life; increased of asset failure and of material consequence; costing more to maintain & operate than to replace	• Other new connections • Other capacity increases • Addressing (realistic) customer expectations		• Medium term safety & environmental improvement projects	• Improved efficiency • Allows capex deferral	• IT & information supporting effective AI ops • Pilot projects, testing new initiatives
4	• Safeguard future options • Enhance network efficiency	• Asset condition 3 - steady state asset replacement programmes • Reliability improvements				• Other NPV>0 opportunities	
5	• Discretionary						

Table 9-1 : Prioritisation matrix

9.3 Changes in Economic Outlook

In preparing this AMP and the expenditure forecasts, several factors contributed to some significant changes in the capex forecasts for the next three years, as compared with that submitted in 2009. The main factors are as discussed below:

- The previous ten year forecast was prepared in a less than buoyant economic environment. The world economy had entered an economic slowdown period and it was anticipated that this would be reflected in reduced network growth for a period of two to three years before the economy would recover. This growth slowdown expectation was reflected in the capex programme, with the capex over the short-term reduced from that forecast in the past.

  However, the maximum network demands recorded in 2009 did not fall as predicted at the time of preparing the previous AMP. In addition, the actual customer connection expenditures for both residential and commercial sectors were higher than the corresponding budgeted numbers. This, in turn, has caused the need for a number of network projects to be brought forward (in comparison with the programme set out in the previous AMP) to cope with higher than anticipated capacity requirements, thereby increasing the near-term expenditure forecast over the previous forecast.

  It is noteworthy that the maximum network demand increased by a greater percentage than the energy delivered. This may reflect that customers are being more discerning in their use of energy as prices increase;

- Approval of the Transpower's North Auckland and Northland (NAaN) reinforcement project has brought certainty around development of the Auckland CBD network. This has given rise to a realignment of our CBD projects with the NAaN timeline – advancing the work associated with the Wairau Rd GXP; and

- A number of significant, new customer driven projects (such as the supply to the Waterview tunnel construction) have been identified over the last 12 months. In addition, the increased level of roading and other infrastructure activities by local and central government agencies also caused a material increase in asset relocation expenditures. These projects have been included in the present expenditure forecast.

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 (following the completion of the NAaN projects). This is illustrated in Figure 9-3, where the forecast capex profile under the present AMP (2010) is compared with the previous forecast (2009).

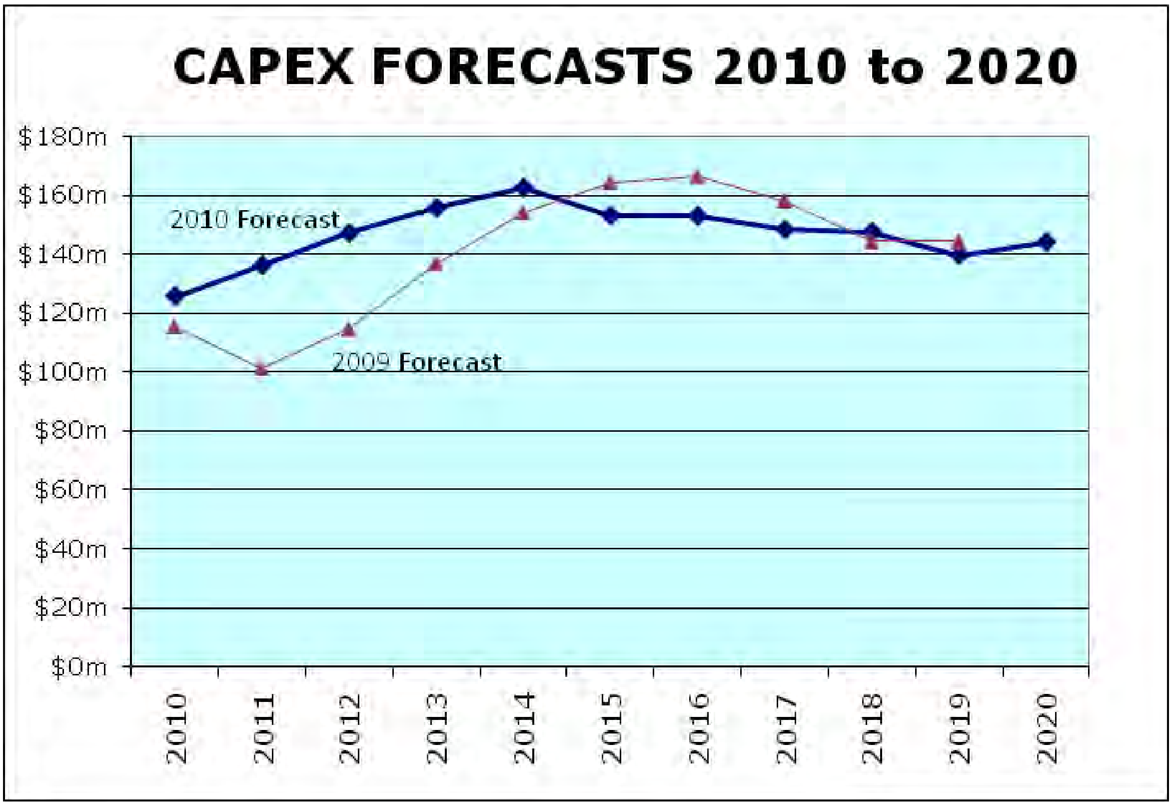


Figure 9-3 : Comparison of capital expenditure profile between this AMP and the previous forecast

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[41]. The table also shows the actual expenditure in the financial year ending March 2009 and the budgets for the year ending March 2010.

Table 9-3 summarises the actual 2009 financial year expenditure against the budget for the year for all capital and operating expenditure categories. An explanation for variances over 10% is provided below.

Explanation of variances more than 10%:

- The higher than budget expenditure in the "customer connection" category ($6.1 million) is a result of mainly residential developments in 2009 substantially outstripping the figures forecast before the period. (The year ending in March 2009 was largely before the slow-down associated with the economic recession, as reflected in housing sales in the Vector supply area);

[41] 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.

- The lower than budget expenditure in the "reliability, safety and environment" category ($3.4 million) is due to deferment of three bunding projects (Atkinson Road deferred to align with other major substation work, Brickworks deferred to allow redesign of transformer foundation, and Liverpool deferred to align with transformer replacement programme);
- The expenditure in the "routine & preventive maintenance" and "fault and emergency" categories appears to be $4.5 million above and $5.9 million below the budget respectively. This is in part due to the manner in which expenditure was categorised at the time and a different approach adopted during the year – some activities were shifted between the two groupings. In addition, the Auckland region experienced a relatively benign year and network storm damage was substantially below the historical average; and
- The higher than budget expenditure in the "refurbishment & renewal" category ($2.2 million) is mainly due to the same factors noted above, as well as more expenditure incurred on repairs on equipment faults identified during routine inspection programmes.

10 Year Forecast of Expenditures	Mar 09 Actual	Mar 10 Budget	Mar 11 Forecast	Mar 12 Forecast	Mar 13 Forecast	Mar 14 Forecast	Mar 15 Forecast	Mar 16 Forecast	Mar 17 Forecast	Mar 18 Forecast	Mar 19 Forecast	Mar 20 Forecast
Customer connection	24.2	9.9	17.5	18.5	19.0	19.7	20.0	19.5	19.2	19.2	18.6	18.5
System growth	33.4	38.7	43.3	45.3	53.5	62.6	52.8	47.7	40.6	42.4	36.1	40.6
Asset replacement and renewal	45.9	42.1	47.5	55.4	57.3	56.7	57.7	63.7	66.6	64.1	63.1	63.1
Reliability, safety & environmental	3.1	5.7	4.5	5.8	5.9	4.3	3.8	3.5	3.2	3.1	3.1	3.1
Asset relocation (including undergrounding)	19.7	18.9	23.3	22.3	20.1	19.4	19.0	18.8	18.8	18.8	18.8	18.8
Capital Expenditure Subtotal	126.3	115.3	136.2	147.2	155.8	162.7	153.2	153.1	148.4	147.6	139.7	144.1
Routine & preventive maintenance	15.3	10.8	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Refurbishment & renewal	15.7	13.5	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8
Fault and emergency	14.0	19.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9	14.9
O & M Subtotal	45.0	44.2	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4
Total Direct Expenditure	171.3	159.5	176.6	187.6	196.2	203.1	193.6	193.5	188.8	188.0	180.1	184.5
Overhead to underground	12.1	12.2	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7

* Figures are in 2010 dollars (million);
** The year reference indicates the end date of the financial year

Table 9-2 : Asset management plan expenditure forecast

Variance between Actual and Previous Year Forecast	Mar 09 Actual	Mar 09 Budget	Variance	Variance %
Customer connection	24.2	18.1	(6.1)	(33.7%)
System growth	33.4	33.3	(0.1)	(0.3%)
Asset replacement and renewal	45.9	44.1	(1.8)	(4.1%)
Reliability, safety & environmental	3.1	6.5	3.4	52.3%
Asset relocation (including undergrounding)	19.7	19.1	(0.6)	(3.1%)
Capital Expenditure Subtotal	126.3	121.1	(5.2)	(4.3%)
Routine & preventive maintenance	15.3	10.8	(4.5)	(41.7%)
Refurbishment & renewal	15.7	13.5	(2.2)	(16.3%)
Fault and emergency	14.0	19.9	5.9	29.6%
O & M Subtotal	45.0	44.2	(0.8)	(1.8%)
Total Direct Expenditure	171.3	165.3	(6.0)	(3.6%)

Table 9-3 : Asset management plan expenditure reconciliation

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
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
CDEM	Civil Defence Emergency Management
CIM	Common information model, as defined by IEC 61970-301
CMS	Customer Maintenance System
CPI	Consumer price index
Cu	Copper
dc	Direct current
DFA	Delegated financial authority
DGA	Dissolved gas analysis
DP	Degree of polymerisation
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
GIS	Geospatial Information System
GXP	Grid exit point, a Transpower owned facility that connects Vector's sub-transmission network to the grid. A GXP may contain more than one bus for Vector's connection.
HV	High voltage – ac rated voltages above 52kV (IEC62271)
HVABC	High voltage aerial bundle conductor
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 conductor
LTOS	Live tank oil sampling
MCR	Maximum continuous rating
MGCU	Mobile generator connection unit
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
NSCC	North Shore City Council
OCB	Oil type circuit breakers
ODV	Optimised deprival value/valuation
Opex	Operational expenditure
PD	Partial discharge
PI	Plant information
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
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
Sub	Substation
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