Wellington Electricity

10 Year Asset Management Plan
1 April 2013 - 31 March 2023

Wellington Electricity

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Any comments or suggestions regarding the Asset Management Plan can be made to:

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Statement from the Chief Executive Officer

Wellington Electricity welcomes the opportunity to submit an updated Asset Management Plan (AMP) for the period 2013-2023. This AMP is a working document, which has been prepared to inform stakeholders of the management of Wellington Electricity's distribution assets, and to meet the Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012.*

Our operations over the last 12 months have continued to focus on delivering high levels of safety, reliability and service to our customers while maintaining a high level of performance from our network assets. This was enhanced with the Control Room relocating to our main office and becoming integrated as part of the Wellington operations team.

Another year of good performance has largely been achieved by continuing to meet the service levels our customers expect from the existing network and continuing to invest in the network assets where they require replacement or some additional attention to ensure they keep delivering a reliable service.

This occurs through good planning and having well defined asset strategies which is where the asset management plan plays an important role in communicating our business drivers and forward work plans.

This has been quite challenging as our region adjusts to a relatively flat economic period and accepts some further contraction in government services which has created a cautious fiscal environment.

There will always be a level of change and uncertainty with each forecast we undertake in relation to external business events or changes in our local economy.

However we are well positioned to manage through periods of uncertainty with the essential service nature of our business and respond well to these challenges. We operate a risk management approach which helps analyse the business impacts and how often we can expect to see risks appear. This becomes a very useful tool to then set a path that allows some proactive controls to be put in place so that our response to and recovery from these unintended events are well managed and result in a lower impact to our business and customers.

To this end we have been focused over the last year in building our systems and capability to manage some of the high impact events other areas around the world have experienced. This has involved developing and testing crisis and major event plans as well as tuning our IT platforms to provide a limited backup should we have to transact business in alternate premises.

A highlight this year was to visit the team at Orion and learn first hand how their world class response and management recovered from a crisis event in Christchurch. Our analysis for a similar sized Wellington event has been captured in the Lifelines report released in November 2012. In summary local utility businesses in our region have a number of large challenges to work through. This will require further support from government to improve infrastructure resilience so we can all be better prepared for not only our economic recovery but for quickly restoring our social wellbeing to provide the impetus for the community to rebuild and move forward.

From a regulatory position it has been a year of landings with the Information Disclosure Determination made in October 2012 and the Input Methodology and Starting Price decisions being delivered in November 2012. These decisions have further influenced our Asset Management position with further detail and discussion included within our latest AMP.

A new requirement is the inclusion of an Asset Management Maturity Assessment Tool (AMMAT). This tool takes an internal review of maturity of the asset management systems and through a gap analysis outlines areas where the business can continue to improve its asset management systems and processes.

The new requirements have identified in some cases, information sets which are either not collected or stored to a level of detail as was required in previous Plans. This has prompted system changes within the business to improve asset data and in some instances lift data accuracy and completeness to improve compliance.

Wellington Electricity has been fortunate that establishing new IT systems has allowed us to build on our data gathering and assessment processes. This ultimately provides an information set of our asset condition to then make informed asset investment decisions. There still remains some gaps which will be addressed as we continue to work through the asset maintenance programs.

Overall Wellington Electricity is managing a mature set of assets which are performing well for the consumers. This plan provides for a consistent level of service, which aims to maintain our position as one of the most reliable networks in the country.

The Electricity Authority continues to promote a Model Use of System Agreement which outlines the interposed relationships between lines businesses, retailers and customers. This Model includes a number of changes which we will engage with our Retailers so we both deliver positive outcomes for our customers.

Being a member of the CKI/Power Assets Group allows Wellington Electricity the ability to access skills and knowledge from our other electricity distribution businesses around the world and have direct access to international best practice in asset management.

In conjunction with our service companies and in alignment with our business strategy, Wellington Electricity will continue to focus on the development of asset management strategies. To ensure that a sustainable business model delivers appropriate levels of capital and operational expenditures to deliver a safe, reliable and cost effective supply of electricity to consumers within the Wellington region.

We welcome any comments or suggestions regarding this AMP.

Greg Skelton

Chief Executive Officer

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1. Summary of the AMP

1.1. AMP Purpose

This Asset Management Plan (AMP) has been prepared for the following purposes:

- To inform stakeholders of how Wellington Electricity plans to manage its electricity distribution assets in order to ensure that connected electricity consumers continue to receive electricity supply at a quality level which is reasonably priced and sustainable
- To provide a working plan for use by Wellington Electricity for the management of the network
- To satisfy the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012.

This AMP covers the 10 year period commencing 1 April 2013 and finishing on 31 March 2023. The plans described in this document for the year ending 31 March 2014 reflect Wellington Electricity's current business plan and are relatively firm for the next two to three years. Beyond three years the plans and strategies are reviewed annually and will be adjusted to incorporate any internal and external business environmental factors as they arise.

Financial values presented in this AMP are in constant price New Zealand dollars, unless otherwise specified.

This AMP was approved by the Wellington Electricity Board of Directors on 27 March 2013.

1.2. Assets Covered

Wellington Electricity's distribution network supplies the cities and council jurisdictions of Wellington, Porirua, Lower Hutt and Upper Hutt. A map of the supply area is shown in Figure 1.2. As of 31 December 2012, there were over 164,750 connected customers. The total system length (excluding streetlight circuits and DC cable) is 4,625 km, of which 62.1% was underground. Peak demands and energy distributed for the last six years is shown in Figure 1.1.

Year to	30 Sep 2007	30 Sep 2008	30 Sep 2009	30 Sep 2010	30 Sep 2011	30 Sep 2012
System Maximum Demand (MW)	555	537	565	583	585*	552
System Energy Injection (GWh)	2,569	2,581	2,595	2,594	2,573	2,554

Figure 1-1 Peak Demand and Energy Delivery

* August 2011 peak demand during an unusual snowstorm pushed the network peak demand to over 615 MW for a period of half an hour until the load control system was operated to shed 30MW of controllable load, in addition to usual load shedding that is undertaken in winter. This prevented the overloading of system components and ensured security of supply during a period when Transpower had reduced capacity on the transmission system into the Wellington area.

Figure 1-2 Wellington Electricity Network Area

1.3. AMP Assumptions

The AMP is based on the following assumptions:
(Note that further details of the assumptions are provided in Appendix B)

Demand growth	Demand growth will continue to be lower than the national average and will remain steady through the forecast period with an annual growth of electricity consumption and demand between 0.5% and 1.0% in some parts of the network, but across the network both demand and volumes will reduce or stay steady.
Quality targets	The quality targets for the Wellington Electricity business in the period 2010 – 2015 will be maintained as per the Commerce Commission's decision paper on the default price path (November 2009).
Regulatory environment	The regulatory environment will encourage Wellington Electricity to continue to employ CAPEX and OPEX to invest in the network to maintain the quality targets.
Shareholders	Shareholders will be incentivised to invest in the network ensuring a sustainably profitable business.
Economy	The commodity markets will remain stable during the forecast period limiting equipment price rises. GDP growth in the area supplied by Wellington Electricity will continue to be lower than the national average, and is likely to be modest at best for the foreseeable future. Industrial and large commercial activity continues to decline.

Business cycle	Wellington Electricity continually undertakes detailed assessments of network assets. It is assumed there will be no uncovering of any new information that changes the premise of network assets being in a reasonable condition. , Increased levels of investment will be required in the later part of the planning period to address asset risk arising from age and condition (as assets approach end of life).
Technology	There will be no dramatic changes that would result in a rapid uptake of new technology leading to higher expenditure or stranding of existing assets. Technologies such as distributed generation and electric vehicles are not a present being taken up in large numbers, as they are relatively high in cost.
Inflation	The inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b are: • All balances reflect increases in costs due to an annual forecast inflation rate of 2.25% obtained from the Reserve Bank website for the September Quarter 2012; and • Labour costs are forecast to increase by CPI plus 1% and materials expenses by CPI plus 0.75%.

1.4. Network Reliability

The reliability of Wellington Electricity's distribution network is high by both New Zealand and international standards. Wellington Electricity plans to maintain supply reliability at current levels over the planning period. The average consumer connected to the network should only experience an outage lasting a little over an hour about once every two years, subject to severe storm events and high wind gusts which can frequently occur within the Wellington region. Wellington Electricity's asset management strategies and forecast levels of expenditure and investment are designed to achieve this by replacing assets that are at end of life and maintaining in service assets through to end of life.

1.5. Network Development

The forecast annual growth of electricity consumption and demand in the Wellington Electricity network area is between 0.5% and 1.0% in some areas, such as the CBD, Churton Park and Whitby (along with their surrounding suburbs). While this drives the need for localised investment, across the network both peak demand and energy volumes have decreased in the past two years. The growth rate on the network is lower than the national average of around 2.0%. Wellington Electricity load forecasts based on long range historic data indicate overall growth through the planning period, however this is not being seen on the network at the present time.

During 2012 Wellington Electricity completed 11kV feeder projects in the CBD and Hataitai to address security and loading constraints within the localised 11kV system. However, as incremental load increases in the CBD due to step-change loads arising from new developments, a new zone substation within the CBD area is required within the planning period (forecast around 2015/16). Other areas with identified capacity constraints are Mana-Plimmerton, Whitby and the Johnsonville-Churton Park areas. Land was purchased in late 2012 at Grenada for the future development of a zone substation to supply the Grenada and Churton Park areas, thus reducing the loading on Johnsonville. This development is expected to be required around 2017. Investigation into suitable sites and configurations for a new substation in the Whitby area is ongoing. A number of smaller 11kV reinforcement projects have been identified within the planning period to address localised constraints identified as being present now, or occurring within the next few years. Projects for the current year include a 33kV reinforcement (cable replacement/upgrade) to Palm Grove zone substation as well as 11kV reinforcement in Tawa, Naenae, and the CBD around the Stadium and waterfront developments.

There is ongoing discussion with Transpower over grid security into the Central Park Grid Exit Point (GXP) and also the implementation of Transpower “Policy” projects including outdoor to indoor 33kV conversions at a number of GXPs in the Wellington area and the replacement of transformers at Central Park and Haywards.

1.6. Asset Replacement and Renewal

The design of the Wellington CBD network is biased towards obtaining high availability and reliability. The Wellington CBD area consists of many high voltage (HV) rings which provide for uninterrupted supply in the event of the loss of any one component. The Wellington Electricity network also comprises a high percentage of underground cabling with over 70% of the sub-transmission circuits being cabled. Of this underground cabling 60km is of pressured gas filled construction, most of which was installed in the 1960’s and is being reviewed as part of Wellington Electricity’s approach to condition based risk management assessment of its assets. Underground cables provide high reliability and resilience against weather and environmental deterioration, however are costly and time consuming to repair and, as demonstrated by the Canterbury earthquakes, vulnerable to major earthquakes. The “Stage of Life” analysis and risk assessment process has been revised for the third time in 2012 for the three major asset types (33kV subtransmission cables, zone substation power transformers and primary distribution circuit breakers) applying a condition based risk management strategy. A number of projects have been identified from this work which is detailed in sections 5 and 6, including the replacement of the Palm Grove 33kV cables, replacement of the Karori zone substation switchboard in 2013, and also setting a prioritised list of replacements for future years (2014 onwards)..

The high number of circuit breakers, the HV feeder rings and the predominance of cabling achieve the high levels of reliability but are asset intensive. As equipment condition factors change and the risk of failure increases, Wellington Electricity is forecasting a period of high capital expenditure on asset replacement and renewal being required to maintain present levels of reliability. Ongoing replacement projects on the Wellington network continue to address the condition of switchgear, transformers and other key supply assets. At the time of asset investment, the asset location and functionality is reviewed to make sure asset replacement solutions are optimised.

Wellington Electricity has programmes in place to regularly monitor the condition of its older assets. This ongoing condition assessment indicates that existing assets are still serviceable and generally in reasonable condition for their age. Notwithstanding this, around 50% of forecast capital expenditure over the planning period is expected to be on the proactive asset replacement and renewal of older assets subject to their condition and risk criteria being met. This level of expenditure is designed to maintain present supply reliability. Improvements in the collection of inspection and condition assessment data is helping to prioritise the replacement of these assets on a risk prioritised basis. Although generally in good condition, a large number of assets are approaching end of life and in the later part of the planning period an increase in the required level of investment will be necessary.

1.7. Asset Management Systems

Since the last AMP, there has been further improvement in the Asset Management systems used, and data collected by Wellington Electricity. The key Asset Management system objectives for 2013 are:

- Continuation of the programme to improve data quality in systems such as GIS and Gentrack. This has progressed well with a large volume of data gathered to update equipment records in GIS, and ongoing work to improve connectivity of the Low Voltage network and customer supply points.
- Further development of the maintenance database, with improvements in the defect management reporting systems and also the improvement of maintenance planning functions. A scope has been developed to upgrade this from the present Access database platform to a specialised maintenance management package such as SAP PM. This will be trialled during 2013.
- Following the successful implementation of a new GE ENMAC control system, development of a stand-alone automatic load control system at the Network Control Room will be re-visited as a key task for 2013. This had been planned for 2012, however was deferred with the relocation of the Network Control Room during 2012. The scope for an upgrade of the ENMAC system to the latest version of PowerOn Fusion (the successor to ENMAC) will also be developed in 2013.

Now approaching the second year of the Field Services Agreement with Northpower, there has been good progress with the business processes that assist Wellington Electricity in filling the gaps of both missing and incorrect information as well as cleansing and validating the data in the Wellington Electricity Asset Management systems. Reporting of all maintenance activities in electronic format has been successful and processes are now well established, and this aids in reporting and analysis by both the Field Service Provider and Wellington Electricity.

1.8. Risk Management

A major objective of the network development and lifecycle asset management plans is to mitigate the risks inherent in operating an electricity distribution business. Risk assessment therefore plays a major role in the prioritisation of network development and asset replacement projects.

The detailed design and operation of the network is not described in this AMP, but it is summarised at a high level to demonstrate it is in accordance with industry standard practices and procedures. These practices and procedures have been developed and refined over time to manage the risks and hazards associated with high voltage electricity distribution.

Wellington Electricity has continued to develop risk assessment methodologies that provide input to the planning of network development, maintenance strategies and project evaluation. This risk based approach has resulted in a number of projects that have been completed over previous regulatory years (refer to section 8.6 for an example of one such project), and also identified a range of upcoming projects to be completed through the planning period In accordance with their risk profile.

Two major projects that commenced in 2012 were the development of major event resilience network planning (in particular emergency overhead subtransmission line routes) and a substation building seismic policy. Both of these projects have been driven by the events associated with the Canterbury earthquakes. The substation building seismic policy was approved and a programme for the assessment of 320 network substation buildings has been developed and started in 2012. This assessment programme is expected to run through until early 2016. Following this work there will be a number of earthquake prone buildings identified that will require seismic reinforcement over the following 10 year period, however the mechanism for recovery of this additional investment is not clear at this time. In addition, detailed plans for bypassing damaged subtransmission cables are being developed, with more than half the CBD gas cable subtransmission routes completed. Further discussion with local authorities on the construction of these routes will occur during 2013.

As part of its Business Continuity Management Policy, Wellington Electricity has Emergency Response Plans to cover emergency and high business impact situations. These plans are periodically reviewed and revised to best meet the business emergency management and response requirements. These plans were routinely tested during 2012 and feedback provided from the exercises was incorporated back into the plans.

1.9. Safety and Environmental Management

Wellington Electricity has continued to build on its strong foundations of past HSE performance and has again noted some significant improvements during 2012. In addition to those previously detailed, notable performance improvements include:

- A positive change in safety culture through an increase in the reporting of events which may have the potential to cause harm, before harm occurs (incident and near miss reporting)
- An improvement in implementing corrective actions from the reported leading indicators so that potential harm incidents are avoided
- Improving employees ability to identify non conformances through the field assessment process via a programme of on the job training and development
- Improved management, reporting and trend analysis of the field assessment process resulting in more assessments being undertaken, timelier closure of actions and a reduction in the total number of corrective actions open at any one time.
- Working with our Service Providers to review and improve their quality assurance arrangements.

Wellington Electricity has also achieved recertification of its Public Safety Management System in early 2013, which is a positive endorsement that the processes and systems are providing a safe environment for consumers and the public.

During 2012, Wellington Electricity continued its safety awareness programmes with schools and contractors, and commenced a series of public safety messages on a major radio network.

2. Background and Objectives

2.1. History and Ownership Overview

Wellington Electricity is an electrical distribution business (EDB) that supplies electricity to approximately 400,000 consumers through over 164,750 installation connection points (ICPs) in its network that covers the Wellington, Porirua and the Hutt Valley regions of New Zealand.

The ownership of Wellington Electricity has changed significantly since the early 1990's. At the start of the 90's, the Wellington City Council Municipal Electricity Department (MED) and the Hutt Valley Electric Power Board (HVEPB) merged their electricity assets. As part of the Energy Companies Act 1992 two new companies were formed, Capital Power and Energy Direct respectively. In 1996 the Canadian owned Power Company Transalta acquired both companies to form a consolidated Wellington Electricity Distribution Network business. Ownership was passed to United Networks in 1998, which Vector acquired in 2003.

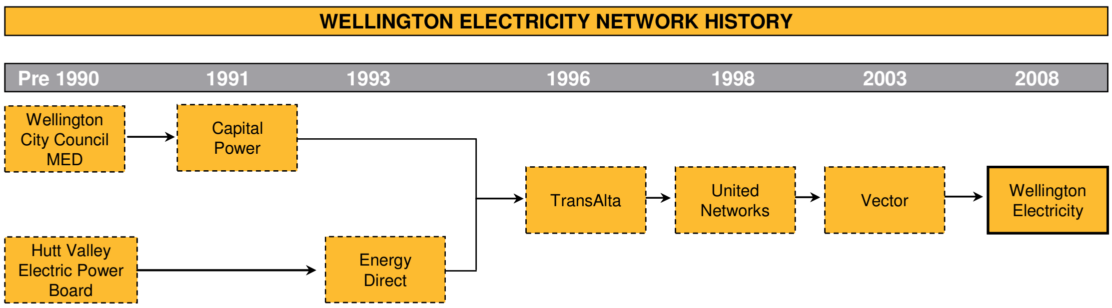


Figure 2-1 Wellington Electricity Ownership History

In July 2008 the network was purchased by Cheung Kong Infrastructure Holdings Limited (CKI) and Hong Kong Electric Holdings Limited (HEH) to create Wellington Electricity Lines Limited (Wellington Electricity). Since then Wellington Electricity has continued to establish the business systems for independent operation and control of the network. Hong Kong Electric Holdings Limited changed its name on 16 February 2011 to Power Assets Holdings Limited (Power Assets) to better reflect the international portfolio of assets.

CKI and Power Assets together own 100 per cent of Wellington Electricity with both companies being members of the Cheung Kong group of companies and listed on the Hong Kong Stock Exchange (HKEx).

Further information regarding the Wellington Electricity ownership structure is available at the website www.welectricity.co.nz.

2.2. AMP Purpose and Objectives

The primary purpose of the AMP is to communicate with consumers and other stakeholders Wellington Electricity's asset management strategies, polices and processes for effective and responsible management of the network assets.

Other goals of the AMP are to:

- Ensure that all stakeholder interests are considered and integrated into the business to achieve an optimum balance between levels of service and the cost effective investment while maintaining regulated service targets. The level of service is reflective of a customer price/quality trade off upon which appropriate pricing can allow the ability of Wellington Electricity to maintain, renew and replace the network assets to meet stakeholder quality needs. The Commerce Commission as the industry Economic Regulator has a part to play in recognising and ensuring that electricity distribution businesses achieve adequate levels of return on investment for their regulated asset base to maintain service quality to consumers;

- Provide a consolidated governance and management framework that encompasses the asset management and planning strategy in a 'live' document
- Address the strategic goals and objectives of the business by focusing on prudent life cycle asset management planning, stakeholder levels of service and appropriate levels of network investment which provide a sustainable and equitable return to the shareholders
- Provide a platform for monitoring and demonstrating continuous improvement in alignment with best industry practice.

The AMP is a key internal planning document and has become a consolidated repository for asset management planning. It is a dynamic document requiring continuous review and adjustment to align with the changes in the business environment.

This is a collectively produced document that draws from external stakeholders and from within the Wellington Electricity business. Contributions to this plan have been received from consumers surveyed, field service providers and the following teams: asset and planning, operations and maintenance, capital works projects, quality, safety and environmental, commercial and finance and the executive. The document is approved for disclosure by the Wellington Electricity Board of Directors.

The AMP is compiled in accordance with the Electricity Distribution Information Disclosure Determination 2012.

2.3. Legislative and Regulatory Environment

Wellington Electricity's principal activity is providing electrical infrastructure and systems that safely and effectively distribute electricity. It is an electricity operator pursuant to section 4 of the Electricity Act 1992. As an electricity operator Wellington Electricity provides electricity lines services to customers in its distribution supply area using its electricity supply system.

Wellington Electricity is subject to a range of legislative and regulatory obligations to ensure its network is safely and efficiently planned, constructed, operated and maintained and that the prices charged for its services fall within regulated allowances. This includes obligations covering:

- Economic regulation under Part 4 of the Commerce Act 1986, including:
    - Information disclosure - the purpose of which is to ensure that sufficient information is readily available to interested persons to assess whether the purpose of Part 4 is being met. Wellington Electricity is subject to the Electricity Distribution Information Disclosure Determination 2012, and
    - Price-Quality regulation – the purpose of which is to regulate the weighted average prices Wellington Electricity is allowed to charge for providing electricity lines services and the reliability of supply of electricity to consumers. Reliability of supply is measured with reference to the duration of interruptions to supply (system average interruption duration index (SAIDI)) and the frequency of

interruptions to supply (system average interruption frequency index (SAIFI) limits). Wellington Electricity is subject to the Electricity Distribution Default Price-Quality Path Determination 2012.

- Price oversight under the Electricity Industry Act 2010 by the Electricity Authority. Price oversight relates to price setting and price movements, including the principles for price development.
- Connection of customers and embedded generators to the network. These obligations are established under Wellington Electricity's Use of System Agreements (UoSA) and are compliant with the Electricity Industry Act 2010 and the Electricity Industry Participation Code 2010 (Part 11).
- Quality of supply standards. This relates to voltage regulation, harmonic voltages and currents, voltage dips, voltage unbalance and flicker standards as per the Electricity (Safety) Regulations 2010 and AS NZS 61000 Electromagnetic compatibility (EMC).
- Employee and public safety under the Electricity (Safety) Regulations 2010 and the Employment Act 1992 to ensure that Wellington Electricity's network assets do not present a safety risk to staff, contractors or the public. Wellington Electricity monitors electricity related public safety as well as staff and contractor safety incidents around its public assets.
- Environmental obligations under the Resource Management Act 1991, the Building Act 1991, the Local Government Act 1974 (particularly with respect to works on roads), the Dangerous Goods Act 1974 and other relevant local authority bylaws. Wellington Electricity has an Environmental Management Plan which sets out its approach to environmental management of its network including in relation to: noise limits; sediment disposal; dust control; spill management.
- Vegetation management in accordance with Electricity (Hazards from Trees) Regulations 2003. This sets out clearance zones in which Wellington Electricity must notify tree owners to arrange management of their vegetation to prevent further encroachment.

Wellington Electricity has had regard for these regulatory and legislative obligations in developing best practice asset management policies and procedures which underpin this AMP.

There are currently no regulated national supply security standards in force. However Wellington Electricity has developed its security standards which specify the minimum levels of network capacity (including levels of redundancy) for its network in accordance with industry best practice. Wellington Electricity's security standards are discussed in section 5 of this AMP.

2.3.1. Economic Regulatory Environment

As noted above, Wellington Electricity is a regulated business and its revenue requirements are subject to regulation by the Commerce Commission under Part 4 of the Commerce Act 1986.

Wellington Electricity's revenue requirements for Electricity Lines Services are established under the Electricity Distribution Service Default Price-Quality Path Determination made by the Commission on 30 November 2012 and applying to the remainder of the regulatory control period from 1 April 2013 to 31 March 2015.

Wellington Electricity recovers its revenue, calculated based on a price path form of regulation that applies a weighted average price cap (WAPC), through charges for the use of the distribution system (otherwise known as Electricity Lines Services charges). These charges are payable by customers and are collected via the customers' retailer.

Substantial changes have been made to the regulatory framework since the commencement of the current regulatory control period in April 2010. Changes to the regulatory framework include:

- Publication of Electricity Distribution Information Disclosure Determination 2012 on 1 October 2012 by the Commerce Commission. This determination introduces new information disclosure requirements which apply to all aspects of disclosure including increased requirements within the Asset Management Plan for greater detail and levels of data to be collected and returned as part of the Plan.
- Publication of the Re-determined Input Methodology Determination (Redetermined IMs) on 15 November 2012 by the Commerce Commission. The Re-determined IMs are important because they set out the rules, requirements and processes applying to the regulation of electricity distribution services. These include amongst other things IMs for: cost of capital, asset valuation, treatment of taxation and cash-flow timing assumptions applying to Default Price Quality Paths.
- Publication of the Electricity Distribution Service Default Price-Quality Path Determination 2012 on 30 November 2012 by the Commerce Commission. This determination involved the Commerce Commission resetting the starting prices applying to the 2010-15 Default Price Path (DPP). This has set the prices Wellington Electricity may charge for the remainder of the regulatory control period, from 1 April 2013 to 31 March 2015.
- Amendments to the Electricity Industry Participation Code 2010 by the Electricity Authority, including in relation to indemnity provisions and prudential security under Part 12A as well as responsibilities for indemnity of Retailers by EDBs under the Consumer Guarantees Act (CGA);
- Introduction of the Model Use of System Agreement (MUoSA) developed by the Electricity Authority. The proposed MUoSA has a number of distinct differences from Wellington Electricity's current Use of Network Agreement. This has resulted in a requirement to develop Wellington Electricity's own Use of System Agreement which is currently being drafted.

2.3.2. Impact of Regulatory Environment on the Business

The regulatory environment has a number of financial, technical and reliability impacts on Wellington Electricity's business. Wellington Electricity regularly engages with the Electricity Authority and Commerce Commission through active participation in submissions on various matters and regular information disclosures. Ultimately these regulatory bodies will make decisions that determine the price/quality trade-off experienced by customers. These include:

<u>Price-Quality compliance</u>

Wellington Electricity must comply with the regulated price and quality requirements set by the Commerce Commission under Part 4 of the Commerce Act and is exposed to possible fines and prosecution if found to be non compliant.

<u>Information Disclosure</u>

Wellington Electricity must provide information disclosures on an annual basis and respond to other information requests. During 2012 a new information disclosure regime was implemented by the

Commerce Commission, taking effect in 2013. This regime has significantly increased the information required to be disclosed. The preparation of the various disclosure requirements is time consuming and costly, requiring the business to alter its processes and information systems to ensure the information requirements can be met.

<u>Starting Price Adjustments</u>

In 2012 the Commerce Commission adjusted the starting prices applying to the 2010-15 DPP. This has resulted in an adjustment to Wellington Electricity's prices, in addition to Consumer Price Index movements, from 1 April 2013 to 31 March 2015. The Commerce Commission will determine a new DPP for Wellington Electricity for the five year period starting 1 April 2015.

<u>Load Control</u>

Historically Wellington Electricity has optimised the required network capacity by using load control to shift loads to reduce demand during peak times. This lowers the capital investment required to deliver the reliability and quality of supply at peak times. In September 2012 the Electricity Authority published a MUoSA which, while voluntary, facilitates retailers and load aggregators undertaking load control. Wellington Electricity supports the customer's right to choose how they participate in the load control market, however this may reduce Wellington Electricity's ability to co-ordinate and manage coincident loads when it is critical to do so. Without certainty as to how this market will operate and the potential for unregulated participants, the quality of supply at peak times could well be compromised. This requires a response to system emergencies and the preserving of distribution voltage quality for the consumer to be included in protocols to be developed between market participants as part of the new requirements of the MUoSA. This protocol would avoid unexpected and unnecessary interruptions for customers and ultimately a need to increase investment in network capacity to ensure quality levels are not degraded and a continuity of supply achieved.

<u>Government Policy - Major Infrastructure projects</u>

Major infrastructure projects driven by Government policy have an impact upon the Wellington Electricity network. The ultra-fast broadband rollout is a positive initiative for New Zealand. However, the roll-out being undertaken by the telecommunications infrastructure provider Chorus has created a significant increase in requests for maps and location mark-outs of network assets. Most notably, there is the impact of contractors striking underground electrical cables whilst installing fibre optic cables, causing interruptions to supply which affect Wellington Electricity's ability to meet the quality thresholds required by the Commerce Commission. Chorus also requires access to network poles for the attachment of fibre services into properties and for street distribution which presents operational issues to Wellington Electricity as the owner of these poles.

<u>Requirements driven by local authorities</u>

Wellington Electricity must comply with local authority requirements, as they undertake their obligations under legislation, which can add costs to the business. Examples of these additional requirements include the assessment and strengthening of earthquake prone buildings. There are lessons from Christchurch with regard to resilience of infrastructure which require Wellington Electricity to conduct further technical and economic assessment followed by consultation with stakeholders on seismic resilience. This AMP does not includes forecasts of the CAPEX and OPEX which may be required to provide an adequate level of seismic resilience. The Council earthquake prone building assessments will obligate Wellington Electricity to make further resilience investments, the costs of which need to be passed through to customers in a similar way to the insurance allowances. In both instances the requirements provide benefit to customers for the long term by avoiding higher recovery costs. Other activities such as roading and drainage projects can lead to relocation work which cannot be fully recovered and contributes to increased costs for the business.

2.4. Interaction between AMP and Other Business Plans

Wellington Electricity's mission is

"To own and operate a sustainably profitable electricity distribution business which provides a safe, reliable, cost effective and high quality delivery system to our customers."

This mission sets the context for all strategic positioning and tactical action planning within the business which effectively drives the asset management planning and delivery. To meet this mission, it is essential for the business to operate in the most commercially efficient manner possible within the current regulatory environment.

The AMP incorporates information from internal business and asset management related documents which cascade down from the Business Plan and Strategy to the asset maintenance and lifecycle plans through to the annual Capital and Maintenance works delivery plans and programmes, as shown below

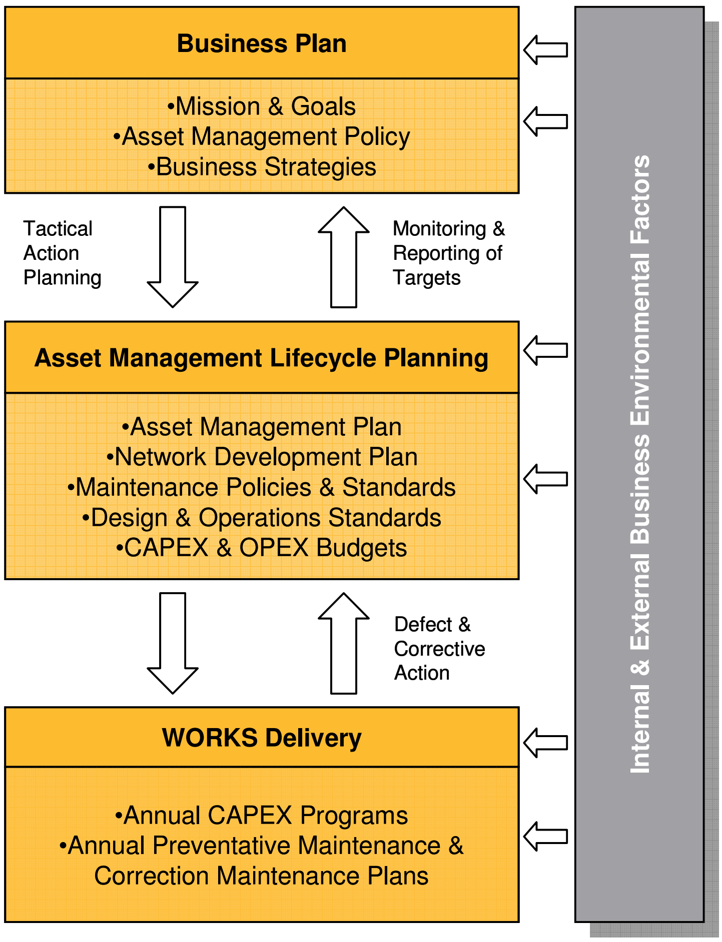


Figure 2-2 AMP Interaction with Business Planning

2.4.1. Business Plan and Strategy

Wellington Electricity's strategic business direction is supported by the Business Plan and aims to deliver a long-term sustainable business to all of its stakeholders.

WELLINGTON ELECTRICITY BUSINESS PLAN

"To own and operate a sustainably profitable electricity distribution business which provides a safe, reliable, cost effective and high quality delivery system to our customers."

INTERNAL BUSINESS ENVIRONMENT

Financial

Meeting our financial targets

Manage our treasury responsibilities

People

Working safely

Developing a great team & organisational culture

Employees are aligned with business goals & direction

Building strong relationships with our service providers

Reputable employer

Assets

Meeting regulatory targets through prudent asset management

Effective life cycle management of assets

Appropriate risk management

Engaged with our stakeholders

EXTERNAL BUSINESS ENVIRONMENT

Consumers

164,750 reasons to provide effective and efficient service

Understand our investment in their future for a quality service

Regulatory

Health & Safety in Employment Act

Commerce Act – Price/Quality Path reset & controls

Electricity Act & Regulations

Economic

Business cycles post recession and pressure to maintain price stability

Image & Reputation

Well managed media and stakeholder communication

Local people managing the business well with high quality service

Political

Responsibility of 4th largest EDB serving nation's capital

Government & business leaders interested in affordable & reliable supply

Managing local & regional council expectations

Figure 2-3 Wellington Electricity Business Plan

Wellington Electricity's Business Strategy is driven in response to both internal and external business environments and defines the company's actions and outcomes to meet the business mission.

The business strategies effectively 'shape' the AMP, taking into consideration the changing regulatory environment and the impacts upon Wellington Electricity meeting the needs and interests of its stakeholders.

BUSINESS OBJECTIVES	BUSINESS GOALS	BUSINESS STRATEGIES
Safety - Our Primary Focus	To achieve zero Lost Time Injuries to staff or contractors. To achieve zero injuries to Members of the Public.	Continuous review of incidents/accident reporting Further development of the Public Safety Management System
Consumers	To deliver an acceptable quality of supply to consumers within the regulated price-quality framework	Effective asset management Relationship management Price-Quality trade-off
Financial & Corporate	To ensure the business is sustainably profitable and meets financial targets	Generate an adequate return to shareholders Manage treasury outcomes
Network & Assets	To operate and manage the assets in a safe, reliable, cost effective and high quality manner.	Produce annual Asset Management Plan Produce Network Development Plan
Our People	To work safely, develop a great team atmosphere and organisational culture. Employees will be aligned with business goals and direction.	Set personal & company objectives/targets for Growth - Stimulate & challenge our people
Regulatory	To comply with Legislation such as the Commerce Act, Electricity Act & Regulations and the Health and Safety in Employment Act.	Establish appropriate business models Manage well all regulatory submissions
Service Providers	Service Providers will be aligned with business goals and direction. To build strong relationships with our service providers	Manage and motivate all service providers to continuously perform ahead of contract requirements and KPI Expectations
Growth	To Identify, explore and develop business growth opportunities within the region and New Zealand.	Explore increased revenue opportunities Leverage ripple control for Demand Side Management opportunities
Image & Reputation	To ensure the business maintains a high quality public image and reputation through local high quality Service.	Support a positive public image through customer engagement - Enhance reputation be delivering a consistent & quality service

Figure 2-4 Wellington Electricity Business Strategies

2.5. Planning Period Covered by the AMP

This AMP covers the 10 year period commencing 1 April 2013 to 31 March 2023 and replaces the April 2012 AMP. Plans for subsequent years of the planning period are likely to be affected by the outcomes of the continued development of the asset management reviews as well as changes to the internal and external environment in which Wellington Electricity operates. The AMP provides clear plans for the management of assets over the next 12 to 36 months, with plans for the subsequent three to seven years being broader and plans for the eight to ten year period being indicative only. This reflects the impact of uncertainty over the longer timeframes.

The AMP will be continuously reviewed in conjunction with the development of asset management strategies driven by:

- A greater understanding of the condition of the Network assets and risks
- Assessment of load growth and network constraints

- New and emerging technologies
- Changes to business strategy driven by internal and external factors

The AMP was approved by the Wellington Electricity Board of Directors on 27 March 2013.

2.6. Managing Stakeholders

2.6.1. Stakeholder Interests and Identification

Wellington Electricity has identified stakeholders, their interests and how interactions are managed by all of the business through a number of activities. The following tables identify the key stakeholders, how they are identified and what their interests are with Wellington Electricity.

Shareholders		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Governance and Board mandates • Board Meetings and committees • Business Plan & Strategic Objectives	Shareholders expect a fair economic return for their investment. Shareholders expect the company to meet industry-leading operational and Health, Safety and Environment standards. Shareholders look to maintain good working relationships with other key stakeholders in the business through engagement with our consumers needs and effective management of the network	• Customer initiated projects produce appropriate revenue levels to meet the cost of capital • Meeting reliability and customer service levels

Consumers		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Customer satisfaction and engagement surveys • Feedback received via complaints and compliments • Media related enquiries and sponsorship • Price / Quality trade-off	The consumers connected to Wellington Electricity's network require a safe and reliable supply of electricity of acceptable quality at a reasonable price. While consumers generally appreciate that delivery of an extremely high quality of supply with no interruptions is unrealistic, expectations can differ as to the level of reliability and quality that can be considered acceptable.	• Meeting reliability and customer service levels • Appropriate investment in the network • Public safety initiatives • Price / Quality trade-off

Retailers		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Electricity Industry Participation Code (EIPC) • Relationship meetings and direct business communications • Via Use of Network Agreement terms	As retailers rely on the network to deliver the energy they sell to consumers, they also require the network to be reliable and to meet agreed service level targets. Retailers are reliant on electricity distribution services to conduct their business and therefore want Wellington Electricity to assist them in providing innovative products and services for the benefit of	• Meeting reliability targets • Achieving customer service levels • Consultation • Development of standard Use of System Agreement taking account of the EA Model.

Retailers		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
	their customers. Retailers have an expectation to access the proposed load control market under the new EA Model Use of System Agreement	

Regulators		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Commerce Act Part 4 and other legislation • Electricity Industry Act 2010 and EIPC • Relationship meetings and direct business communications • Industry working groups • Information disclosure	To ensure that the consumer achieves a supply of electricity at a fair price commensurate with an acceptable level of quality.	• Meeting reliability compliance targets and controls for price and quality • Compliance with legislation, engagement and submissions as required • Monitoring information disclosures • Engagement with Regulators and Regulatory Impact Statements.

Staff & Service Providers		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Team and individual direct discussion • Employee satisfaction surveys • Relationship meetings and direct business communications • Contractual agreements	Staff and contractors want job satisfaction, a safe and enjoyable working environment and to be fairly rewarded for the services they provide. Contractors also want assurance around work delivery continuity and the mitigation of working hazards by appropriate asset management planning.	• Health & Safety policies and initiatives • Forward planning of work through asset management practises • Performance reviews • Life balance

Transpower		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• EIPC • Relationship meetings and direct business communications • Annual planning documents • Grid notifications & warnings	Transpower obtain sustainable revenue earnings from the allocation of connected and inter-connected transmission assets. Wellington Electricity under the Electricity Industry Participation Code (EIPC) will operate and interface under instruction as and when required. Further assurance is required that all downstream connected distribution and generation will not unduly affect their assets.	• Implementation of Operational standards and procedures • Appropriate investment in the network • Regular meetings

Central & Local Government		
How are the interests identified?	What are their interests / expectations?	Accommodation of interests / expectations?
• Through legislation • Relationship meetings and direct business communications • Focus working groups	Local Councils require that appropriate levels of investment are made in the electricity network to allow for levels of local growth. Regional Councils require that both current and new network assets do not affect the environment. Central Government's interests are mainly managed through the respective ministries e.g. MBIE, to ensure the general public receive a safe, reliable and fairly priced electricity supply. All three require appropriate emergency response and contingency planning to manage a significant civil defence event. Councils undertaking their obligations under legislation that impact upon electricity network buildings, e.g. seismic assessment and reinforcement of earthquake prone buildings.	• Compliance with legislation, engagement and submissions as required • Emergency Response Plans • Environmental Management Plans • Identification of costs associated with the reinforcement of substation buildings. These costs fall outside of existing funded works programmes. Wellington Electricity has submitted to Central Government on this shortfall for cost recovery under a DPP.

Figure 2-5 Stakeholder Identification

2.6.2. Managing Conflicting Interests

Safety will always be a 'non negotiable' attribute when managing a stakeholder conflict. Wellington Electricity will not compromise the safety of the public, its staff or service providers.

Other stakeholder interests that conflict will be managed on a case-by-case basis. This will often involve consultation with the affected stakeholders and may involve the development of innovative "win-win" approaches that are acceptable to all affected parties.

Wellington Electricity is a member of the Electricity and Gas Complaints Commission scheme, which provides dispute resolution process for resolving customer complaints.

Wellington Electricity's Use of Network Agreements provide a dispute resolution process for managing conflict with retailers.

Wellington Electricity actively engages in consultations undertaken by the Electricity Authority, Commerce Commission and Government departments. The introduction of Part 4 of the Commerce Act 1986 resulted in several submissions to the Commerce Commission relating to the development of Input Methodologies and the reset of the 2010-15 DPP. The Part 4 process allows for a "merits appeal" process with the High Court, which applies a materially better outcome standard against the initial Input Methodology decision, while preserving the long term benefits to consumers.

Wellington Electricity is obliged to follow approved business policy to ensure it meets its obligations and responsibilities to deliver an electrical supply in accordance with all legislative requirements.

2.7. Wellington Electricity Structure and Asset Management Accountability

2.7.1. Governance

The Wellington Electricity Board of Directors is responsible for the overall governance of the business. The Board has approved capital and operational expenditure budgets and business plans for the 2013 calendar year. Information is provided to the Board as part of a monthly consolidated business report that includes health and safety reports, capital and operational expenditure vs. budget, reliability statistics against targets and consumer satisfaction survey results.

All network capital projects greater than $400,000 require approval from the Capital Investment Committee (CIC). The CIC comprises, as a minimum, one company director and the CEO. The CIC meets on a regular basis to review and approve projects and to be appraised of progress on approved projects.

2.7.2. Executive and Company Organisation Structure

The Wellington Electricity CEO leads the business management, implements the company mission and is accountable for overall business performance and direction.

International Infrastructure Services Company (IISC) is a separate infrastructure services company which provides services to Wellington Electricity.

Further services are contracted to Wellington Electricity through external service providers.

As Wellington Electricity is part of the CKI group of infrastructure companies, it can access skills and experience from across the world. For example, CKI's Australian group companies (which distribute electricity to over 1.8 million customers) have considerable knowledge and experience in electricity distribution business asset management including strategy and planning. This group has provided the IT systems and platforms into Wellington Electricity to allow synergy gains across the business. Being part of a larger CKI group of companies has provided Wellington Electricity with direct access to international best practice systems to support world class asset management.

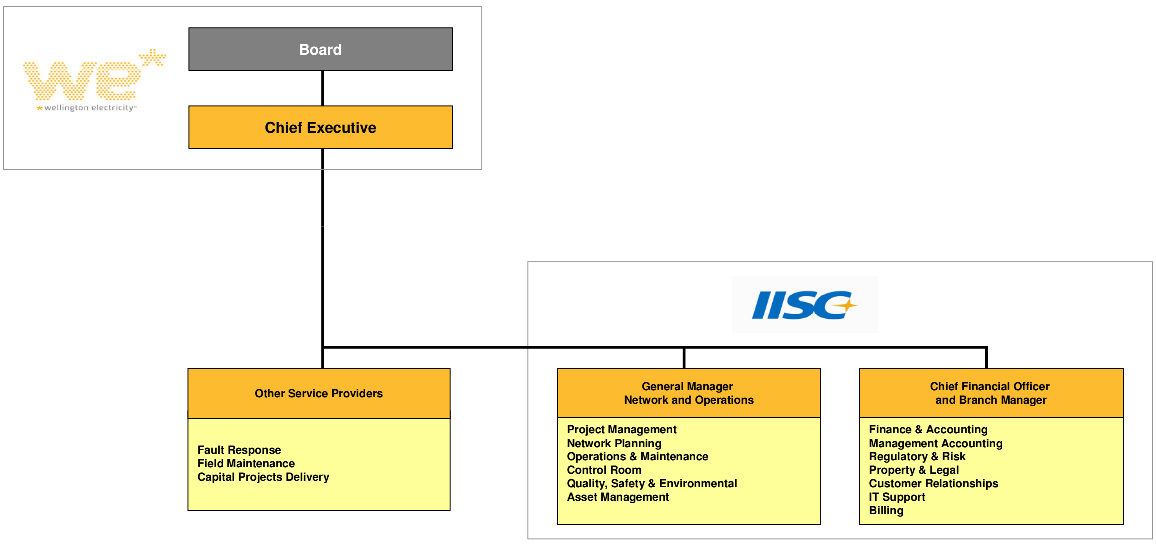


Figure 2-6 Wellington Electricity Organisation Structure

2.7.3. Network & Operations Team Structure and Asset Management Accountability

The management of network assets for Wellington Electricity falls under the accountability of the IISC Networks and Operations team, however the entire business has some direct or indirect interaction with the network assets on a daily basis.

The General Manager – Network and Operations is accountable for the delivery of asset management services to Wellington Electricity. These services include asset planning, project management, capital expenditure delivery, operations and maintenance and safety, quality and environmental performance.

A notable structure change occurred during 2012 where the Network Operational Control service was taken over by IISC and the Network Control Room was relocated to Wellington Electricity's head office in Petone. These changes have provided benefits such as increased interaction between the operations, projects and engineering functions of the business through its main service provider, IISC.

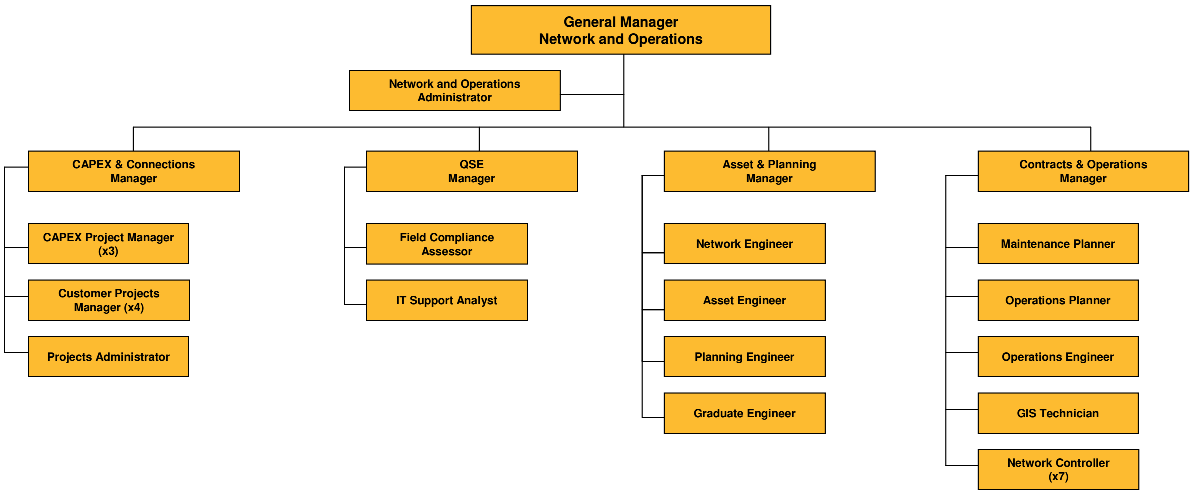


Figure 2-7 IISC Network and Operations Support Structure for Wellington Electricity

2.7.4. Finance and Commercial Team Structure and Asset Management Accountability

Financial and accounting support for the management of network assets is also provided for within the IISC structure for service delivery to Wellington Electricity. The Finance and Commercial team provides indirect interaction with the network assets through managing support systems on a daily basis.

The Wellington based Chief Financial Officer is responsible for all indirect asset management functions including customer service, retail services, regulatory management, legal and property management as well as financial modelling and accounting support services.

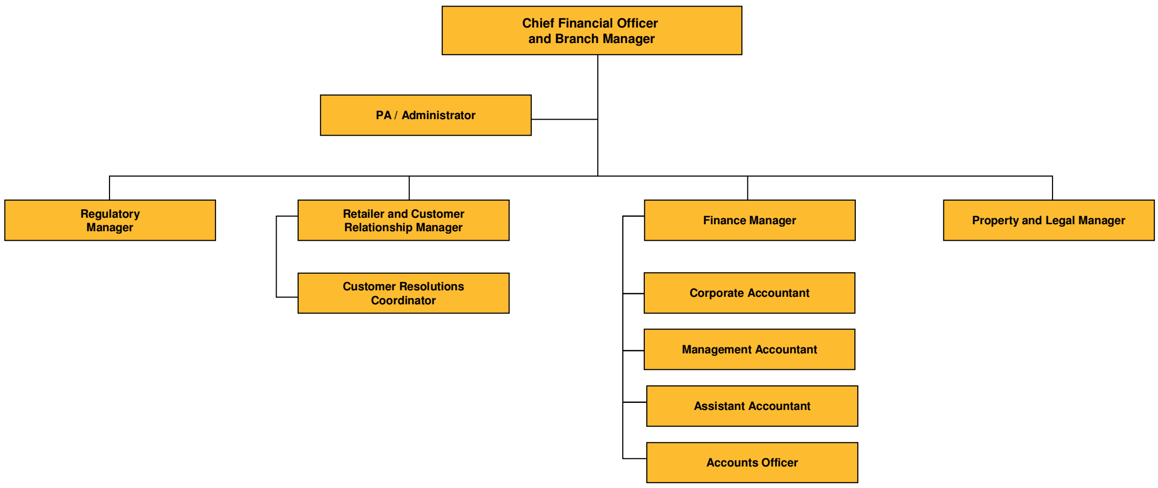


Figure 2-8 IISC Finance and Commercial Support Structure for Wellington Electricity

2.7.5. External Service Providers – Field and Network Operations

Wellington Electricity operates an out-sourced field services model on its network utilising a number of service providers for core field and network functions. Northpower Ltd was successful in being appointed as Wellington Electricity's Field Service Provider from 2011 for a four year term, at which time the contract can be renewed or re-tendered.

The Field Services Agreement with Northpower has been designed to deliver a number of strategic objectives for Wellington Electricity. A particular focus is on alignment with Wellington Electricity asset management strategies, to obtain a greater understanding of the condition of network assets and to improve the integrity of asset data with population into the Wellington Electricity information systems.

In summary, the out-sourced field operations and the approved Wellington Electricity service providers are:

<u>Fault Response and Maintenance (Northpower)</u>

- Fault Management – 24/7 response for fault restoration
- Preventative Maintenance – asset inspection and condition monitoring including capture, storage of asset condition data and reporting this information to the asset owner
- Corrective Maintenance – remedial maintenance on defective assets
- Value added services – safety disconnects and reconnects, on site cable mark-outs, sub-transmission standovers and provision of buried asset plans provided to third parties
- Minor connection services and livening
- Management Services – management of network spares, updating of Geographical Information Systems (GIS) and other supplementary services as required

This contract is managed under the terms of the Field Services Agreement which includes KPI and performance targets that the Contractor is required to meet, with penalties for poor performance, as well as incentives for high levels of achievement. The contract is managed with a series of monthly meetings to cover off key functional relationships between Wellington Electricity and Northpower, as well as a Leadership committee meeting bi-monthly comprising the senior managers from both businesses. The cost of work undertaken is based upon the commercially tendered unit rates which formed part of the original

RFP evaluation. It is the responsibility of the Contract and Operations Manager to ensure the work completed is kept within agreed budgets and the work is delivered within the required quality and timeliness targets. To achieve financial performance under this contract, and to ensure a strategic balance is achieved between maintenance and renewal activities, expenditure by the contractor is limited under Delegated Financial Authorities, above which Wellington Electricity must provide approval to proceed, and this is detailed further in section 2.10.1.

Contractors at an on-site project briefing

<u>Contestable Capital Works Projects (Northpower, Transfield Services and Connetics)</u>

- Customer initiated works – new connections, subdivisions and substations, undergrounding and relocations
- Network initiated works – asset replacement projects and cable/line reinforcements

This work is covered by Independent Contractor Agreements (and under the Field Services Agreement with Northpower) which outline the terms under which the work is completed, including any relevant KPIs, other performance requirements such as defects liability periods, performance bonds as well as insurance and liabilities provisions to limit the risk exposure of Wellington Electricity. Contracts are managed on an individual basis per project and there is a structured reporting and project close-out process, as well as field auditing during the course of the works.

Contestable capital works projects are generally competitively tendered to three Contractors, however in some cases there is the ability to sole source low value works or where only one supplier can provide the required service. In the case of sole supply, pricing is benchmarked against comparable market data. Under the project management framework the scopes are well defined and there are stringent controls in place for variations to fixed price work. Unit rates have been agreed with all contractors for certain types of repetitive, low value work. It is the responsibility of the CAPEX and Connections Manager to ensure work undertaken is managed contractually to deliver value to the business.

Connetics replaced Lineworks as the third contractor on the Wellington Electricity network during 2012 when they purchased the Wellington based Lineworks operation. Prior to commencing operations on the network, Connetics were required to undertake contractor pre-qualification to meet Wellington Electricity's requirements.

Vegetation Management (Treescape)

- Vegetation Management – tree clearance programme, tree owner liaison and reactive availability
- This out-sourced contract is in the process of being re-negotiated to move to a "unit rate for service delivery" model in line with the network maintenance Field Services Agreement with Northpower.

Management of this contract is handled in a similar manner to the Field Services Agreement with monthly meetings and performance incentives in place.

Contact Centre (Telnet)

- Contact Centre – providing a dispatch function for all HV and LV outages, management of customer and retailer service requests, outage notification to retailers and handling general enquiries
- This out-sourced contract is planned for re-negotiation in 2014

Wellington Electricity manages and audits all service providers and also collates reports on network operations and maintenance performance and expenditure, customer satisfaction, safety statistics and network reliability.

Wellington Electricity will continue to review the extent that these activities remain out-sourced in order to achieve optimum asset management outcomes.

2.8. Asset Management Systems and Processes

Wellington Electricity's stakeholders have invested significantly in IT systems which place Wellington Electricity in a strong position for establishing best practice asset management services to its customers.

2.8.1. Systems for Managing Asset Data

This section of the AMP identifies the key repositories of asset data used in the asset management process, the type of data held in the repositories and what the data is used for. Areas where asset data is incomplete are identified and initiatives to improve the quality of this data are disclosed.

2.8.1.1. SCADA

A GE ENMAC Supervisory Control and Data Acquisition (SCADA) system is used to assist real time operational management of Wellington Electricity's network. SCADA provides for remote control and indication of telemetered field devices such as circuit breakers and substation equipment; it also provides high voltage network connectivity overview. The ENMAC system was fully commissioned during 2011 following the separation of the automatic load control system. The ENMAC system provides a total integrated solution of SCADA, DMS (Distributed Management System) and OMS (Outage Management System) with the legacy Foxboro SCADA system fully separated from the ENMAC SCADA system to perform the automated load control functionality.

The SCADA system only provides operation, monitoring and control of the network at 11kV and above. Low Voltage (400 Volts or below) outages are recorded by the GE ENMAC Calltaker system utilised by the Outage Manager at the Wellington Electricity Contact Centre. The Calltaker system electronically interfaces with the Field Service Provider's outage management system to dispatch field staff for fault response.

Wellington Electricity is investigating the upgrade of ENMAC to an updated version of the GE system, known as PowerOn Fusion. Investigations will continue in 2013 and the upgrade may be implemented in 2014 or later.

Two other systems related to the SCADA system are being investigated for upgrade.

- TrendSCADA - a proprietary data historian tool which is used by network operations and for planning purposes. There are a number of shortfalls with this product such as the resolution of data that can be stored, limited ability to retrieve large datasets, as well as a limited suite of analysis tools.
- Load Control - this is presently being performed by the Foxboro SCADA system which has remained since the conversion to ENMAC. This requires replacement in the short term and options are being investigated for its replacement either as an integrated part of the GE system, or as a replacement standalone package.

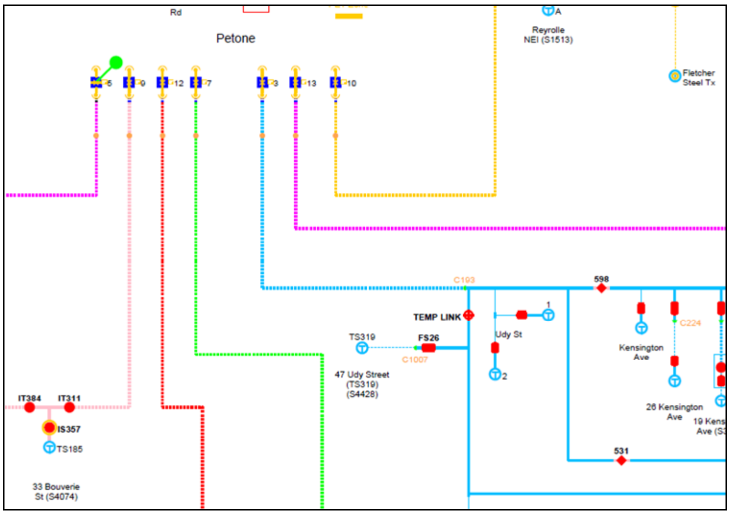


Figure 2-9 Screen shot of ENMAC SCADA/DMS system

2.8.1.2. Geographic Information System (GIS)

The geographic information system (GIS) is a representation of the system fixed assets overlaid on a map of the supply area. Wellington Electricity uses the GE Smallworld application for planning, designing and operating the distribution system and is the primary repository of network asset information. A process is in place to link asset condition data in the maintenance systems to the GIS information to further improve asset management outcomes. Information is exchanged from the GIS to the Field Service Providers systems, as well as to the Wellington Electricity maintenance databases, on a nightly basis ensuring all systems have the latest asset data. By linking the GIS system with the maintenance management databases, analysis of asset populations is improved and geospatial analysis of defects, maintenance and test history, and asset performance can be undertaken with ease which will aid engineering decision making.

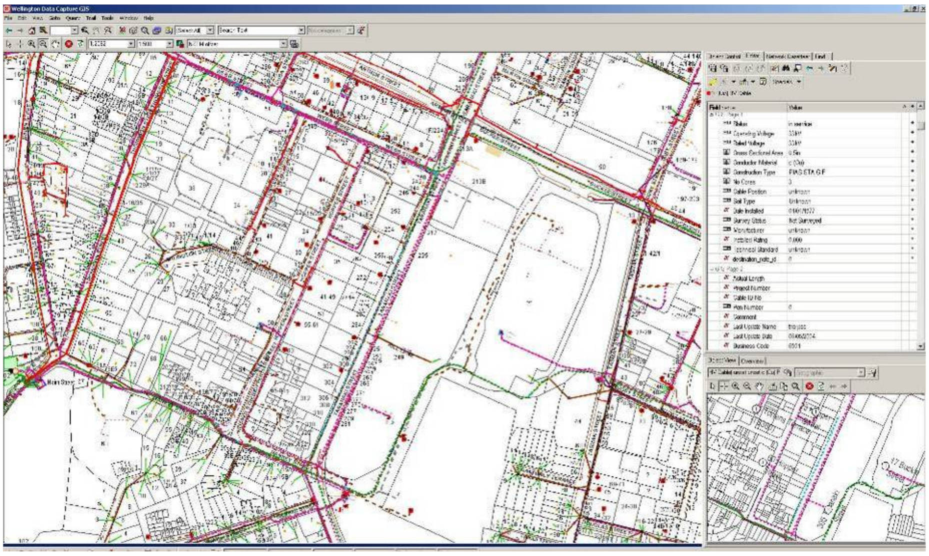


Figure 2-10 Screen shot of Smallworld GIS system

2.8.1.3. ProjectWise

Wellington Electricity stores all drawings and historic asset information diagrams in ProjectWise where users can access PDF files of all substation and system drawings.

2.8.1.4. DIgSILENT Power Factory

Power Factory is a leading network simulation tool used to model and simulate the electrical distribution network and analysis of load flows for development planning, reliability and protection studies. The Power Factory database contains detailed connectivity and asset rating information. Wellington Electricity completed a review of the Power Factory model in 2011 and has confirmed its accuracy and completeness and views this tool as a key part of optimising the network and planning development projects.

To ensure ongoing accuracy, the model is progressively updated with new network information as assets are replaced or as the network is extended. This is completed by the Planning Engineer following receipt of information from the projects team. Wellington Electricity has explored processes which can ensure it remains synchronised with the actual power system through such means as an automated cross reference with GIS, however the low volume of updates means a manual update process is efficient for the time being. This will be reviewed if the volume of updates increases significantly in future years

2.8.1.5. Cymcap

Cable rating information is derived via CYMCAP (cable ampacity and simulation tool) which is used to model the ratings of underground cables at all voltages for both existing cables in service and also for new developments.

2.8.1.6. DIgSILENT Station Ware

Station Ware is a centralised protection setting database and device management tool. It holds relay and device information, parameters and settings files. Station Ware interfaces directly to Power Factory to allow for protection discrimination studies to be carried out.

2.8.1.7. Hard Copies and Spreadsheets

Wellington Electricity has much of the historic asset condition information of the network in the form of hard copies and/or spreadsheets of inspection records and test results. These are stored in various locations, both electronically, or in hard copy. Examples of asset condition data and maintenance record data held include:

- Scanned and printed copies of inspection results
- Spreadsheets of transformer oil analysis
- Scanned copies and hard copies of historical cable test results

Wellington Electricity has worked through the challenge of establishing electronic records into the new maintenance database in order to more effectively manage asset information for future decision making.

Initially a number of gaps existed in maintenance history and test results for some assets. These assets have been prioritised for inspection or maintenance ahead of those with a known history (within an acceptable risk profile) to establish a baseline of knowledge on those assets. Given the progress on the maintenance programme in recent years, Wellington Electricity has built up a reasonably sound knowledge of assets on the network. However due to the gaps in historic information, trending and analysis using data from prior to the network purchase date is not always possible. Over time this will improve as more information is obtained and, for new assets installed, a wider range of information is recorded from installation and throughout the asset lifecycle.

Wellington Electricity is continuing the acquisition of data and test results for all asset categories and maintenance activities which operate on multi-year cycles. It is anticipated that detailed condition information may not be complete for all asset categories for several years. This will impact upon the ability of Wellington Electricity to meet the requirements for an application for an alternative price path.

2.8.1.8. Maintenance Database

Wellington Electricity has developed a maintenance management database to store the maintenance history of network assets and to electronically capture maintenance data. Over 15,000 historic maintenance records from the period 2007 to 2010 were entered into this database at the time of the field services contractor transition. Maintenance data is regularly provided electronically by the Field Service Provider on completion of maintenance works such as condition assessments, inspection and test results and to record defects against the asset. The database has reporting functionality to enable Wellington Electricity to verify the work completed, administer the record accuracy and allow sorting and searching to support the design of future maintenance and replacement programmes based upon the historic inspection and condition assessment results. Wellington Electricity is focussing on additional resources to review the data to identify gaps with asset records and where priority actions are required on network assets, as well as to schedule future works.

The database, although functional to meet Wellington Electricity's current maintenance management requirements, is considered an interim solution. Preliminary scope development occurred in 2012 to trial SAP PM (Plant Maintenance) which is used by a group company, Citipower/Powercor in Australia, as well as several large utilities in New Zealand. Following this trial, which is expected to occur in mid 2013, work will continue to translate the existing business rules and strategies into the full implementation of an integrated maintenance management system.

The asset data within the existing maintenance database can be migrated to the final maintenance management system once implemented.

2.8.1.9. GenTrack

GenTrack is an application designed to manage Installation Control Point (ICP) and revenue data as well as deliver billing services. GenTrack is populated and synchronised with the central ICP registry. It interfaces with the GIS and ENMAC systems to provide visibility of consumers affected by planned and unplanned network outages. GenTrack also interfaces to SAP financial system for billing.

2.8.2. Financial Systems

SAP is the financial and accounting application used by the business as the commercial management platform. It is an integrated finance system for billing, fixed asset registers, payroll, accounts payable and general accounting.

2.8.3. Summary Table

The following table provides and overview of the information systems used by Wellington Electricity and which part of the asset management and network operations processes the systems are used in.

	Physical attributes	Equipment ratings	Asset condition	Connectivity	Customer service
SCADA / ENMAC		✓		✓	✓
GIS	✓	✓		✓	✓
Project Wise	✓	✓			✓
Power Factory		✓		✓	
Station Ware	✓	✓			
Spreadsheets / hardcopy	✓	✓	✓		
Maintenance Database	✓	✓	✓		✓
GenTrack				✓	✓
SAP (Financial)					✓

Figure 2-11 Asset Data Repositories

2.8.4. Process for identifying Asset Management Data requirements

Wellington Electricity recognises that robust information is needed to drive the asset management activities such as maintenance, refurbishment and replacement. Completeness of data in the GIS system is required to drive asset strategies and is regarded as the central repository of network information. Initially data is entered at the time the asset is created and gathered through the life of the asset in systems such as the Maintenance Database and Stationware. However, it is recognised that requirements may vary as asset management strategies change. Identification of asset management data requirements are covered by asset maintenance standards as well as through an evolutionary process as new needs are identified within the business or through changing regulatory requirements. Asset Management data requirements and processes are also specified in the Field Service Agreement with Northpower.

Where gaps in data exist, which may be required for maintenance and renewal processes, changes are made to the systems to obtain this data (or at least to make provision for it) however it takes time to reach a level of completeness of new data and accuracy needs constant monitoring and controls put in place.

2.8.5. Data quality

Wellington Electricity is routinely reviewing its business data to check the quality of the records in the IT systems (GIS, Gentrack and the Maintenance Database), as inconsistencies have been found between some of the data in different locations. Initiatives have been identified to establish one 'source-of-truth' system for each category of information, and the subsequent synchronisation of data between the various repositories. Work is continuing to update missing or discovered assets and nameplate information stored in GIS, identify and fix network connectivity in GIS which is critical to ICP data management, and improve the quality of maintenance data being reported from the field.

The Field Services Agreement has a number of business processes developed that over time are assisting Wellington Electricity in filling the gaps of both missing and incorrect information as well as cleansing the data in the systems (with a particular focus on the GIS data).

Data quality is managed by the use of system controls such as mandatory fields, fixed selection lists and ongoing Quality Assurance (QA) processes in the major systems (GIS, Maintenance Database). User training is also provided to ensure users understand what information is required and why particular information is captured and its use within the overall Asset Management process. Specific areas where there are limitations in the availability or completeness of data are listed in the table below.

System	Limitation	Control in Place
GIS	Equipment name plate information missing for some assets	Name plate data collected as part of inspection process and GIS updates in place following inspections Periodic reporting of asset categories to identify where gaps exist and follow up with GIS updating process to correct gaps on inspected equipment
GIS	LV connectivity is incomplete in some places	Ongoing project to improve LV connectivity and create accurate representation of LV feeders and open points

System	Limitation	Control in Place
GIS/Gentrack	ICP Connections to transformers	Historically some ICPs were not connected to the correct transformers in GIS and there is a mismatch between the Gentrack system and GIS. This is progressively being corrected and new processes are in place to ensure new ICPs are connected to the correct transformer (physical connection in the field is correct)
GIS	Some asset types not represented in GIS or incomplete	Asset types such as relays, batteries and chargers, ripple plant and some DC trolley bus equipment is not stored in GIS and these are being progressively added following installation or inspection activities
Maintenance Database	Some required data not collected for early records	Entry forms now have mandatory fields in place to control data being inputted Historic entries being reviewed to fill in gaps
Maintenance Database	Condition Assessment (CA) scores incorrect for early inspections arising from misunderstandings of new Field Inspectors	Field Inspectors given briefing sessions to improve understanding of CA scores Annual re-inspection will provide correct information from second pass
Powerfactory	New network additions, capacity upgrades or replaced equipment may be delayed in updating the model	Network planning engineers update the model to reflect new and updated system components from GIS and at project completion Project Managers are required to submit relevant information at the completion of projects to allow the models to be updated to reflect actual state
Stationware	Not all station protection relay settings have been captured in Stationware	Settings are updated at the time of projects being undertaken, or gathered as required to undertake protection and network studies Settings are intended to be updated following relay testing where the technician can enter as-left settings following the testing
ENMAC SCADA	Not all network branches have ratings assigned to them leading to possible system overload	System limitations prevent all branch ratings from being stored and displayed. This will be remedied in upgrade versions of ENMAC (v5.14 onwards) Spreadsheet of branch ratings provided to Network Control as an interim measure

Figure 2-12 Overview of Asset Data Gaps and Improvements

2.9. Asset Management Strategy

The asset management strategy that Wellington Electricity has adopted aligns with the asset management policy, business strategies and goals listed in section 2.4. Wellington Electricity intends, during 2013, to develop management strategies for each of the asset categories on the network which will cover the whole of the asset lifecycle from selection, acquisition and construction, through operations and maintenance to end of life replacement and disposal.

The strategies will link together various pieces of existing knowledge and information within the business including technical specifications, maintenance standards, as well as renewal and replacement plans as documented in section 6 of this plan. The strategies, when finalised and documented in future plans, will incorporate cost-benefit analysis information supported by risk assessments of the different scenarios. These strategies will be socialised with a range of stakeholders to ensure they are widely understood and that the asset management practices of the business are aligned.

2.10. Process Overview

The three main processes that Wellington Electricity uses as part of managing network assets are:

- Inspection and maintenance
- Planning
- Investment selection

The interaction of the processes is illustrated in the diagram below. Each of these processes and the asset works plan is described in detail in the following sections.

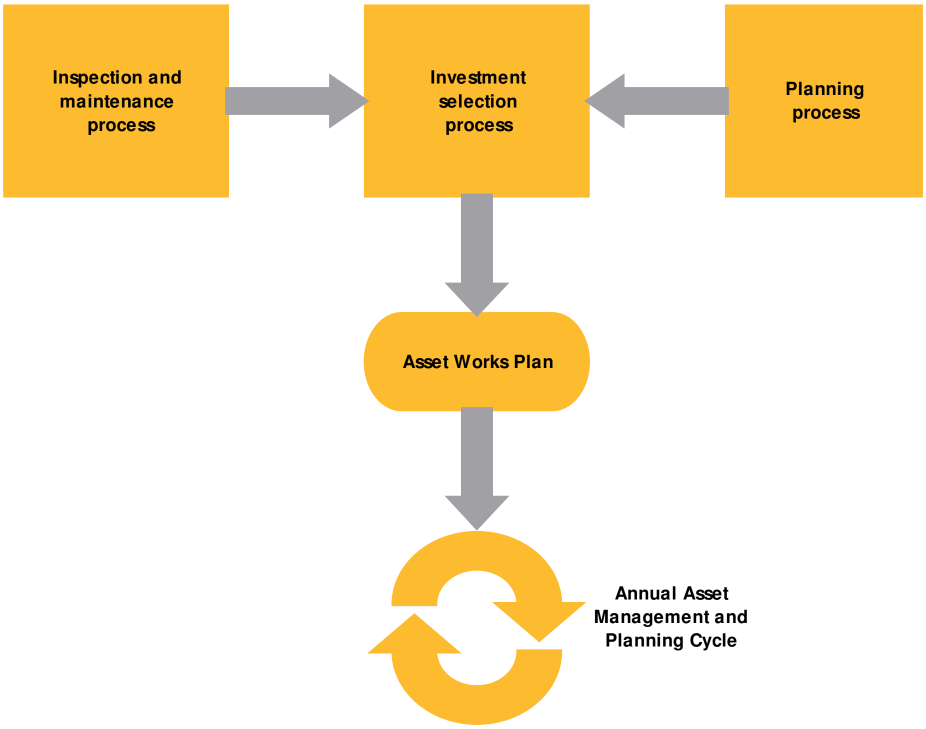


Figure 2-13 Asset Management Processes

A key output from these processes is the Asset Works Plan (AWP), which in turn feeds into the annual asset management and planning cycle. The AWP is discussed in more detail in a subsequent section of this chapter. The development of the AWP is ongoing, and is being continuously reviewed for input into the AMP process.

2.10.1. Inspection and Maintenance Processes

The existing asset inspection and maintenance process is centred around the Preventative Maintenance (PM) plan that is prepared annually by the Wellington Electricity engineering and maintenance groups. The PM plan lists all assets by group and details the inspection and routine maintenance activities that are required for them. Each type of asset has an associated standard driving the policy that details the scope and frequency of the inspection and maintenance required for that asset category. These standards and associated policies are discussed in more detail in Section 6 (Lifecycle Asset Management). The timing and scope of these activities are optimised by a number of factors including:

- Safety (both operational and public)
- Condition (assets that show signs of deterioration may be inspected more regularly)
- Age (older assets may be inspected more regularly than new ones)
- Experience of how often inspections are required (e.g. for substation buildings)
- Type history (assets that have known issues may be inspected more regularly)
- Operation frequency (assets that have operated frequently under fault conditions)
- Risk (likelihood and consequence of asset unavailability)
- Manufacturers recommendations

The PM plan is then scheduled by the Field Services Provider into a PM programme. The Field Services Provider is responsible for implementation of the programme and is held accountable for this through their service contract. The Field Services Provider will inspect the assets, undertake a condition assessment of the asset or assets, identify any asset defects, carry out the routine maintenance and also carry out corrective maintenance (i.e. correction of issues uncovered during routine inspection) provided the total cost of this is under a threshold set by Wellington Electricity. The inspection and test results, condition assessments, defect assessments and work records are reported to Wellington Electricity on a regular basis with prescribed maintenance data recorded into the Wellington Electricity maintenance database. Wellington Electricity engineering staff analyse the maintenance data via the maintenance database and in discussion with the Field Services Provider may approve further corrective maintenance or initiate the investment selection process to address refurbishment and renewal works. Additionally, the cyclic review of asset performance (e.g. feeder performance) may initiate either corrective or project works. Wellington Electricity completed enhancements to the maintenance database during 2012 which allow for the monitoring and detailed reporting of outstanding and completed defects, as well as analysis of aging and overdue defects. This enables the business to undertake greater analysis of defects and manage the risk associated with the pool of current defects. Further enhancements to the reporting and analysis capabilities are expected during 2013 as further business requirements are identified.

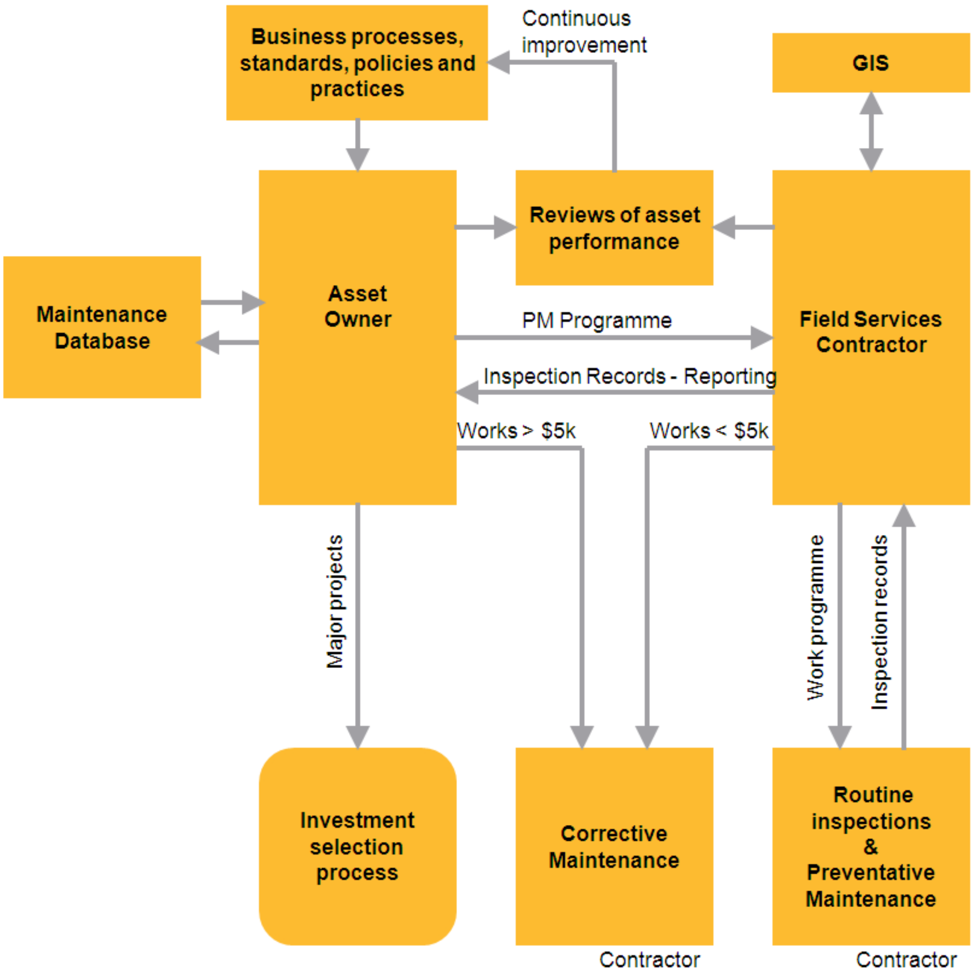


Figure 2-14 Inspection and Maintenance Process

2.10.1.1. Review of Inspection and Maintenance Process

Wellington Electricity continuously reviews the outcomes from its asset inspection and maintenance processes to ensure they are effective in meeting business needs. A number of initiatives have already been put in place to improve data capture and records management such as identifying missing asset information in the GIS and other systems, updating equipment ratings and undertaking a condition assessment of the assets. Increasing the understanding of each type of equipment enables targeted maintenance programmes or revisions to the standards to be made. During 2011 and 2012, large improvements have been made in the asset information held in the GIS, as well as in understanding asset condition, defect types and asset specific issues. From analysis of defects and asset failure modes, maintenance standards are then updated as required to reflect new issues and modes of failure. Where necessary, corrective programmes of work are put in place to address specific risks. It is envisaged that once an overall view of asset condition and asset risk is known, from two or more cycles of the maintenance programme, the intervals between inspections or invasive maintenance activities can be optimised.

2.10.2. Planning Process

Network constraints are identified by reviewing the capacity and the security of the network on a regular basis against network standards and policies. Should a constraint be identified, options for addressing it through reconfiguration of the network (e.g. by moving an open point) will be considered first, to optimise the use of existing network capacity. Should no reconfiguration options be available using the existing network infrastructure then other options will be investigated as part of the investment selection process. The options may include both network (installation of new lines, cables and transformers to create new capacity or allow utilisation of nearby capacity) and non-network solutions (such as localised generation or demand side management initiatives). Key inputs to the capacity and reliability review are the planning criteria, which is kept constant, and load forecasts, which are updated on a yearly basis. These are described in detail under separate headings in Section 5 (Network Planning).

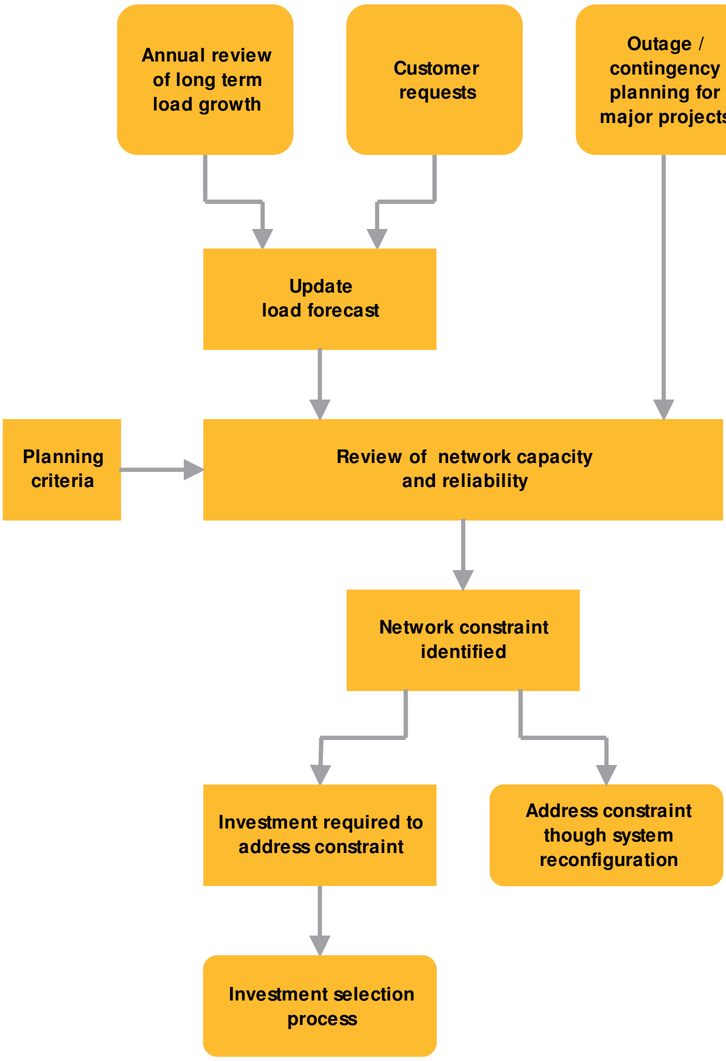


Figure 2-15 Planning Process

2.10.3. Investment Selection Process

This process describes the way in which network investments are taken from a high level need though to a preferred investment option that in turn results in a business case. It includes consideration of a long list of options, refinement of the long list to a short list of practicable options followed by detailed analysis and selection of a preferred option. The Asset Works Plan is the repository for all potential network investments including those at the early 'needs have been identified' stage and 'preferred option' stage.

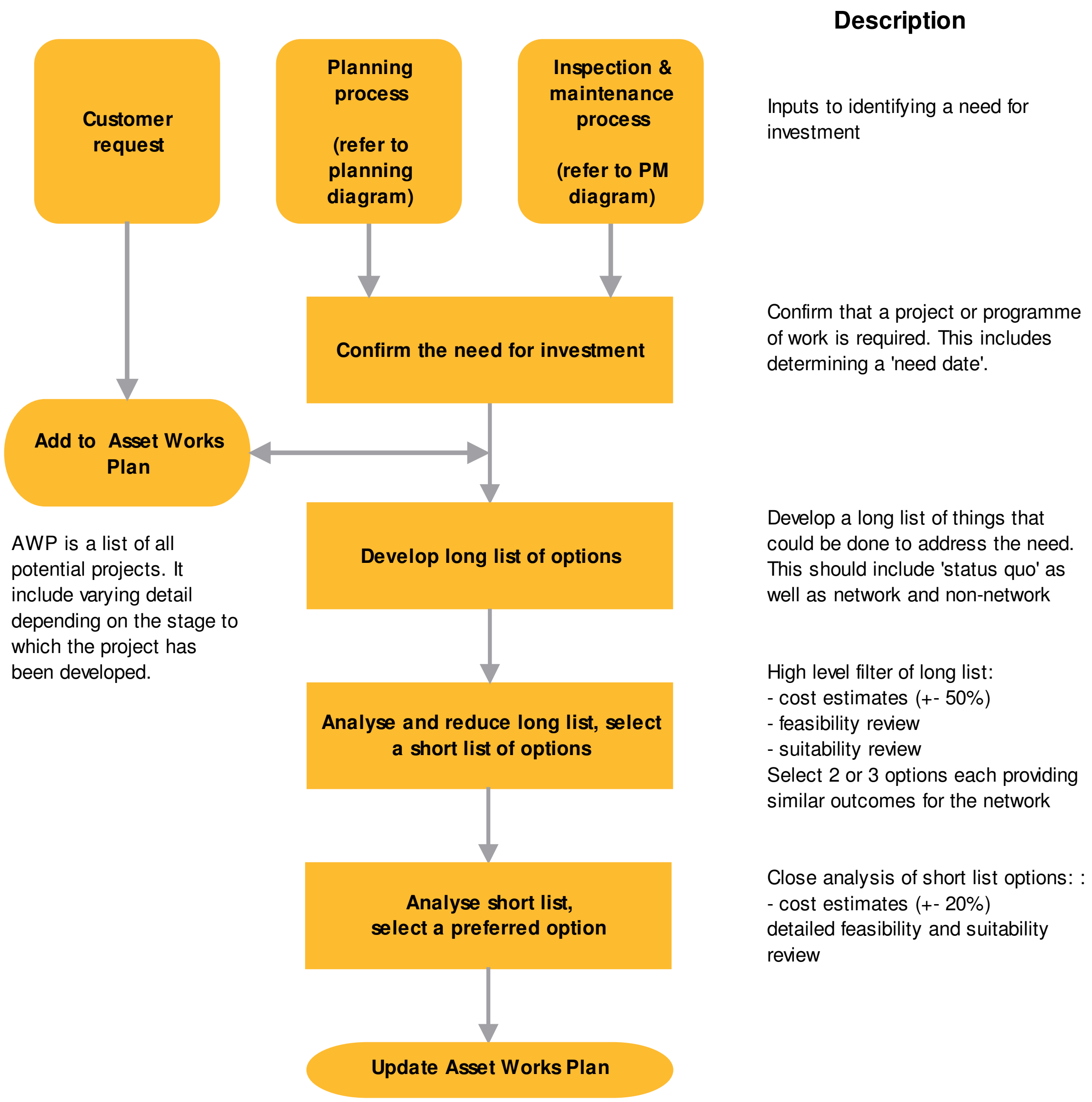


Figure 2-16 Investment Selection Process

2.10.4. Asset Works Plan

The Asset Works Plan (AWP) comprises a list of potential projects at the high level 'need has been identified' stage and at the 'preferred option' stage of the 'Investment Selection Process'. The AWP is a dynamic list that includes dates of when projects are required. It includes projects up to ten or more years in the future and is continually updated and amended as new 'needs' are identified, project details are refined and projects are executed. Every year the prioritised projects identified in the AWP for the next financial year will be developed to the 'preferred option' stage of the Investment Selection Process. This list of projects will then be scheduled for delivery. Following prioritisation, each project will be matched against the available budget for capital works and a list of projects for the following year (i.e. the capital works spend plan) will be prepared for both Board approval and CIC approval.

2.10.5. Processes for Measuring Network Performance for Disclosure Purposes

SCADA and ICP allocation information stored within the ENMAC database[1] is extracted using reporting tools to provide the business with fault (unplanned) and planned outage information. All relevant details of HV and LV faults are entered into the ENMAC fault log database, which will calculate the impact of each fault on SAIDI and SAIFI. Where supply is restored progressively through switching over a period of time, the switching sequence will be recorded and used as the basis for recording the actual SAIDI impact on customers. The ENMAC database may also be used to measure other performance metrics, for example the faults per 100 circuit-km performance indicator.

Information on the reliability of the network is available on an ongoing basis throughout the measurement period and will be regularly reported both within the business and to the Board through its monthly reports.

2.10.5.1. Unplanned Outages

The process for handling and recording the impact of unplanned outages is illustrated diagrammatically below.

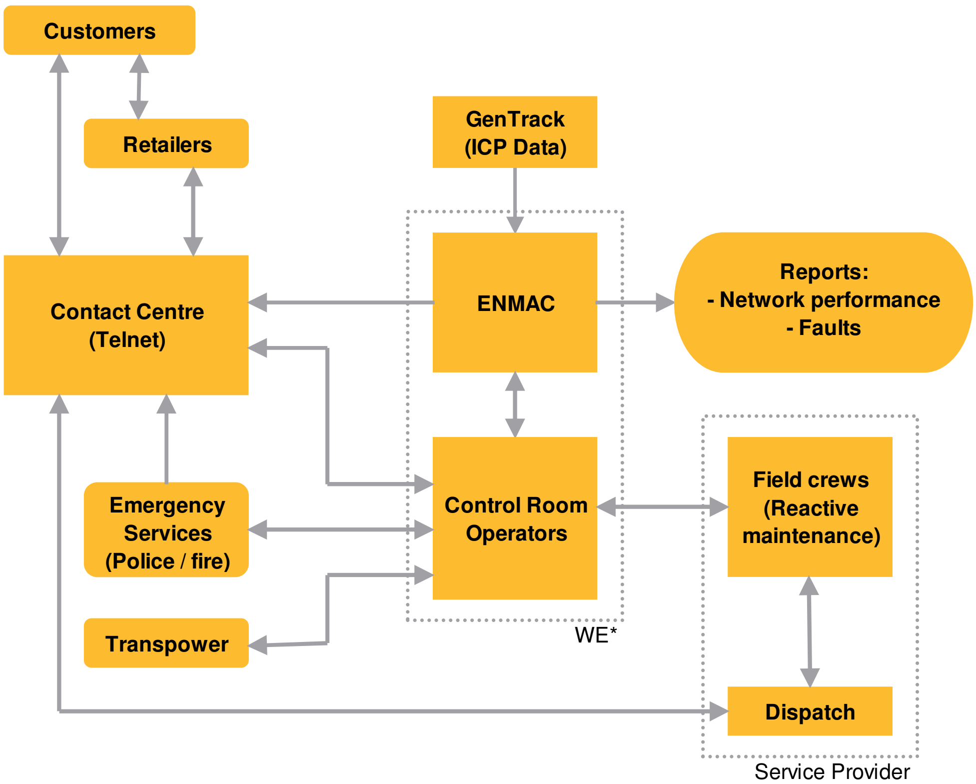


Figure 2-17 Unplanned Outage Process

The major components that comprise this system are:

- Contact Centre service provider
- Control Room: Operators and ENMAC
- Field service providers (fault response and maintenance)

[1] SCADA includes the status of circuit breakers and switches as well as system voltages and currents. ICP allocation information comprises connections made to each part of the network.

Low Voltage Faults (400V or below)

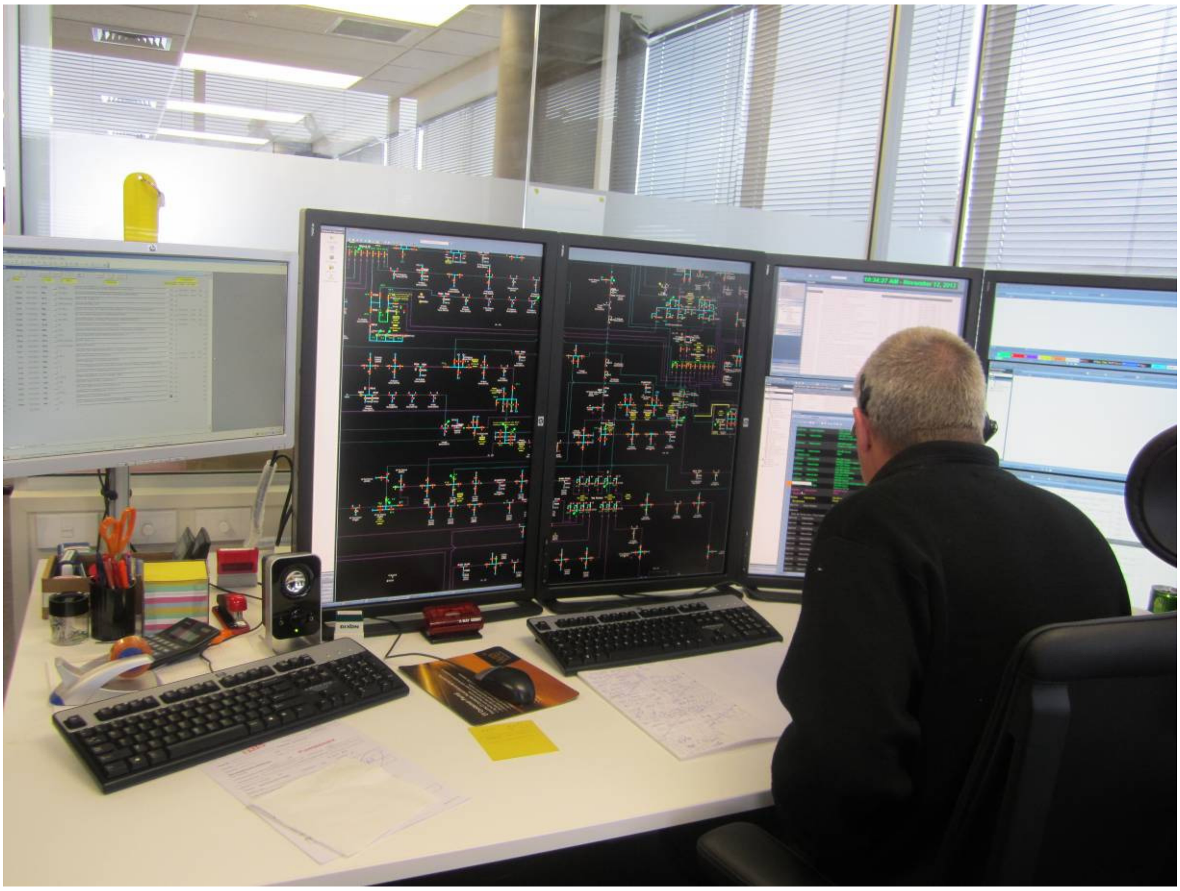
Notification of a LV fault may be raised though calls from customers (either direct to the Contact Centre or via the customer's energy retailer). The majority of energy retailers have an electronic interface into the Wellington Electricity's ENMAC Calltaker system to directly input the LV fault details from the customer. Other options available to energy retailers are email and facsimile. The Contact Centre receives this information and sends it via the ENMAC Calltaker system to the Field Services Provider's dispatching system.

The Field Services Provider dispatches a faultman to the faulted customer(s). Updated information is fed back from the field to the Contact Centre via the outage management systems to enable the customer (via their energy retailer) to be kept informed of progress of the fault and its restoration.

High Voltage Faults (11kV or above)

Currently the Control Room via the SCADA system will identify a fault or tripping on the 11kV (or above) network thereby generating a fault within the ENMAC SCADA system. A dispatch request to the Field Services Provider for field response is automatically generated via the ENMAC Calltaker system.

As identification of the fault is carried out and supply is restored, the Control Room operators will (via the field crews) progressively update the fault log in ENMAC. Fault logs are available from ENMAC via a reporting tool. On a regular basis, these logs are interrogated and network performance statistics are obtained.



A Network Controller at the new Petone Network Control Room

2.10.5.2. Planned Outages

Planning of outages for both maintenance and capital works is undertaken by the Field Services Provider and other approved capital works service providers in conjunction with Wellington Electricity.

For both maintenance and capital works the service providers must provide the outage requirements in a prescribed format to comply with the Wellington Electricity Operational Standards requirements such as the minimum prior notification periods to which the request must be made to the Control Room before the day of work. The Control Room will schedule the planned outage and develop the switching schedule and relevant test and access permits for return to the service provider before the day of the planned outage.

Maintenance Planners use the Preventative Maintenance plan to produce a forward schedule of planned works for the Control Room to assist in the optimisation of planned outages and to minimise the number and duration of planned outages on the network.

The Wellington Electricity customer services team discuss major outages, and outages that affect sensitive customers directly with those customers prior to the outage being confirmed. Following confirmation of an outage, the control room will liaise with the retailers (who notify all affected customers) to advise them in advance of planned works that will interrupt their supply. As the outage takes place, ENMAC is updated with switching operations. A log of affected customers, and the duration of the interruption to their supplies is recorded in ENMAC. This log is interrogated to determine network performance.

The planned outage process is illustrated below.

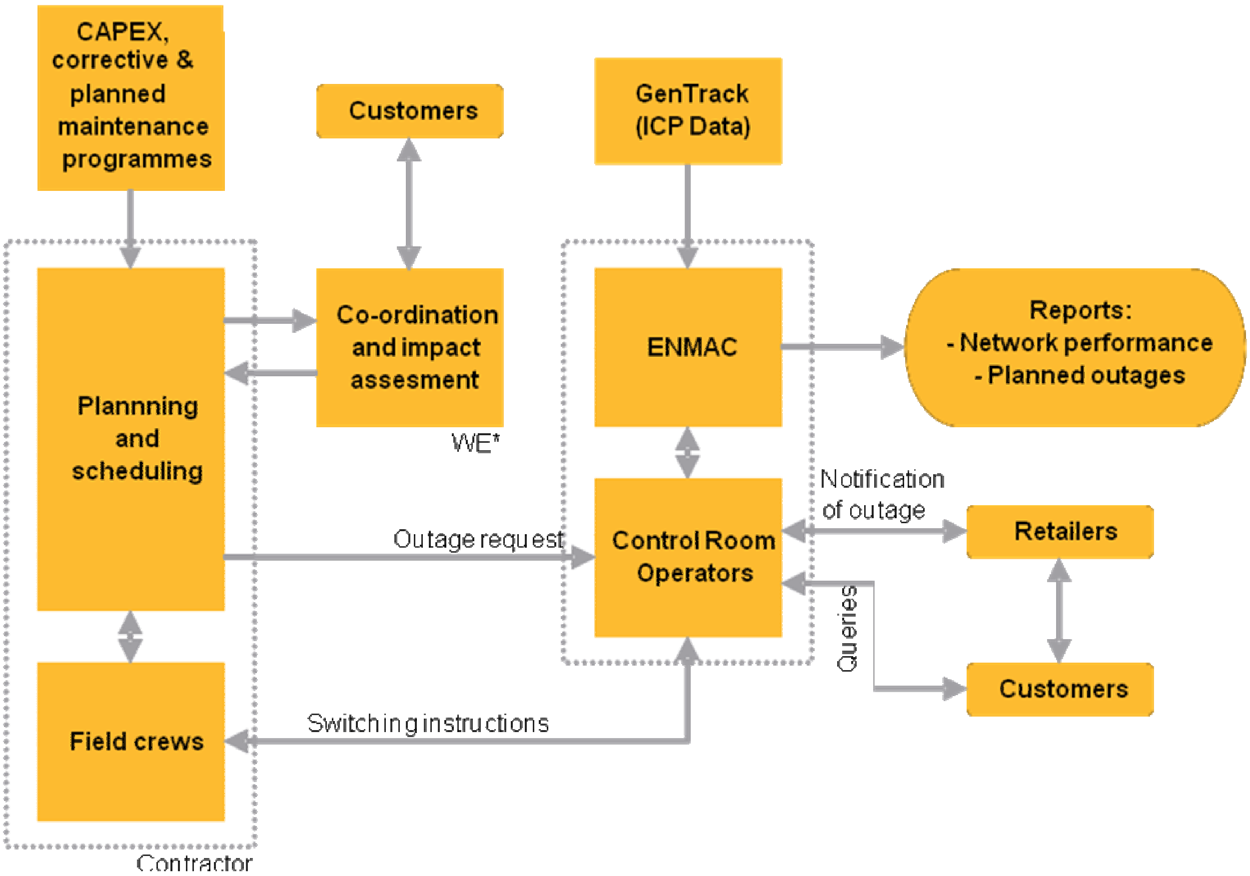


Figure 2-18 Planned Outage Process

2.11. Asset Management Documentation and Control

Wellington Electricity has a range of documents relating to the asset management system ranging from high level policy documents, through technical standards for procurement, construction, maintenance and operation of network assets. In addition, there are guidelines and network instructions to provide line of sight asset management and covering the entire asset lifecycle. The keystone document is the Wellington Electricity Asset Management Policy which provides direction for the asset strategies, processes and supporting documents.

All documents such as policies, standards and guidelines follow the structure of the Controlled Document Process adopted by Wellington Electricity, with a robust review and approval process for new and substantially revised documents. Intranets and extranets make the documents available to both internal users and external contractors and consultants. Generally documents are intended to be reviewed every three years however some documents, due to their nature or criticality to business function, are subject to more frequent reviews.

In late 2012 Wellington Electricity commenced a gap analysis of where asset lifecycle documents are missing or incomplete. This will be used to drive the development of new documents as required. As part of this process, Wellington Electricity is undertaking a review and update of standards which were inherited from previous owners of the Wellington Electricity. In particular the review covers technical standards for procurement, construction, maintenance and standard construction drawings. Whilst older in nature, these documents still contain technical information which is relevant to the ongoing operation and management of Wellington Electricity's assets and are therefore considered a valuable resource.

A strict change control process is in place to ensure that new or altered documents are released to staff and contractors in a controlled manner, with management approval from both organisations. Contractors have access to the Wellington Electricity extranet to obtain the latest copies of controlled documents. Policy documents are used internally within Wellington Electricity to drive strategy and as a guide to the development of standards, guidelines and network instructions. Where Contractors are required to undertake certain tasks or follow procedures, these are provided to them in the form of a controlled document, either as a standard, guideline or network instruction.

Contract agreements with Wellington Electricity's contractors also define the terms under which information has to be provided to Wellington Electricity relating to tasks completed on the network including faults, planned maintenance and corrective maintenance. GIS systems are required to be updated following alterations or renewal of system components, as well as updating data gaps where asset attribute or nameplate information has not been captured. The GIS system and Maintenance Management System are owned and controlled by Wellington Electricity and it is the responsibility of the Contractors to update information within these systems to enable Wellington Electricity to retain control of this information.

2.12. Communication of Asset Management Strategies and Policies

Wellington Electricity communicates its asset management strategy through the annual disclosure of the Asset Management Plan, as well as making a range of the asset management documents such as policies, standards and guidelines available to internal and external stakeholders.

Monthly management meetings are held with both the main Field Service Provider and other Contractors working on the Wellington Electricity network. The monthly management meetings track progress to Key

Performance Indicators covering safety, operations, maintenance, capital works and general technical requirements, including the roll out and embedding of new policies and standards which apply to the work being undertaken by the Contractors. In addition to monthly management meetings, asset management information is communicated through staff group technical, project specific and operational meetings.

Wellington Electricity presents asset management information to internal and external stakeholders as relevant. Managers are aware of the asset management plans and strategies and are expected to communicate these to their teams as required. Staff generally demonstrate an awareness of asset management strategies and if unsure of specific elements of the strategy, are aware of the correct parts of the organisation to find more information.

2.13. Capability to Deliver

The Board and Senior Management team review this AMP against the business strategy and ensure alignment with business capability and priorities. Management consider this plan to be reflective of current business capability. Where new business requirements exist beyond the current practice, or where non-business as usual items are identified, these will be assessed against the present business capability and, where necessary, further resources will be considered (whether financial, technical, or contractor resource) to help the business achieve these new business requirements.

A key area for specific development during 2013 is in preparing a resource strategy for the delivery of the long term asset management needs. The intention is to map the technical, design, management and field delivery requirements of the OPEX and CAPEX expenditure programme contained within this plan to determine what resourcing levels are required and to identify where future gaps in resource capability pose significant risk to achievement of the asset management goals.

3. Assets Covered

3.1. Distribution Area

Wellington Electricity's distribution network covers the cities of Wellington, Porirua, Lower Hutt and Upper Hutt. Wellington City is one of the major metropolitan centres in the country with high density commercial developments. It is also the seat of government and includes Parliament Buildings and the head offices of most government departments. A map of the network area is shown below.

Figure 3-1 Wellington Electricity Network Area

As of 31 December 2012, there were over 164,750 connected customers. The total system length (excluding streetlight circuits and DC cable) was 4,625 km, of which 62.1% was underground.

The Wellington CBD is the largest business and retail centre for the region, although there are also significant retail centres in Lower Hutt, Porirua and Upper Hutt. Apart from within the CBD there is widespread residential load throughout the network area. This is interspersed with pockets of commercial and light industrial load.

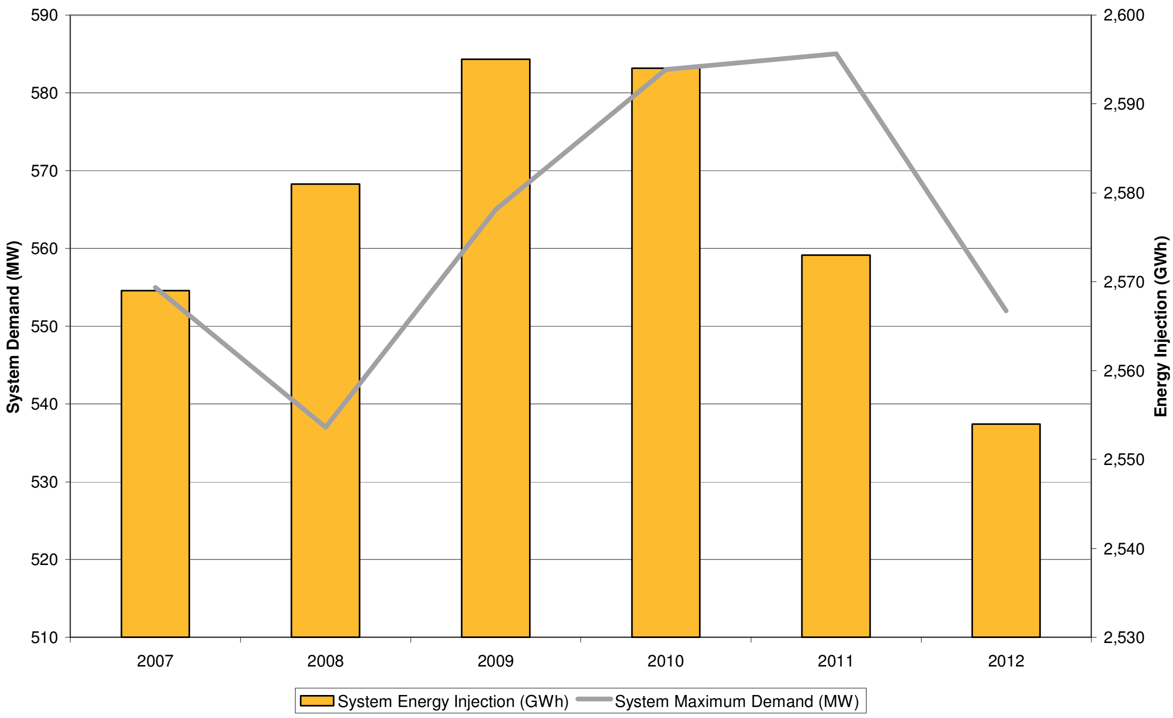
Major customers with significant loads include Parliament, Wellington Airport, Centreport, Wellington, Kenepuru and Hutt Hospitals, Victoria University, as well as council infrastructure such as water and wastewater treatment and pumping stations. Wellington Electricity also supplies the electrified suburban railway network and the trolley bus network. The network area is notable for the absence of large industrial loads.

The network area covers four local councils, namely Wellington City, Hutt City, Upper Hutt City and Porirua City. In addition to the local councils, the Wellington Regional Council covers the entire network area. The different council areas have varying requirements for permitted activities for an electrical utility, for example in relation to road corridor access and environmental compliance.

The trolley bus network is supplied through Wellington Electricity owned DC assets comprising 15 converter transformers, 15 mercury arc rectifiers, 4 solid state rectifiers and 53 DC circuit breakers. There are approximately 53 km of underground DC cables linking various DC substations. These DC assets are managed in accordance with a network connection and services agreement with NZ Bus Limited (the sole customer supplied by these assets) and are therefore not covered by this AMP.

3.2. Load Characteristics

Peak demands and energy distributed for the last five years is shown below.



Year to	30 Sep 2008	30 Sep 2009	30 Sep 2010	30 Sep 2011	30 Sep 2012
System Maximum Demand (MW)	537	565	583	585*	552
System Energy Injection (GWh)	2,581	2,595	2,594	2,573	2,554

Figure 3-2 Peak Demand and Energy Delivery

* August 2011 peak demand during an unusual snowstorm pushed the network peak demand to over 615 MW for a period of half an hour until the load control system was operated to shed 30MW of controllable load, in addition to usual load shedding that is undertaken in winter. This prevented the overloading of system components and ensured security of supply during a period when Transpower had reduced capacity on the transmission system into the Wellington area.

3.2.1. Typical Load Profiles

Typical load profiles for CBD and residential loads are shown below. These graphs illustrate that CBD loads are relatively even throughout the year with a slight trend towards a summer peak, and their daily profile is relatively flat though the day. Residential loads however are winter peaking with a pronounced dip in demand during the middle of a typical working day. Load profiles that are representative of urban and residential areas are shown on the following graphs of Nairn Street and Naenae zone substation demand respectively. At a system wide level, demand and volume has declined over the past two years, however in certain locations where development is occurring there is growth observed.

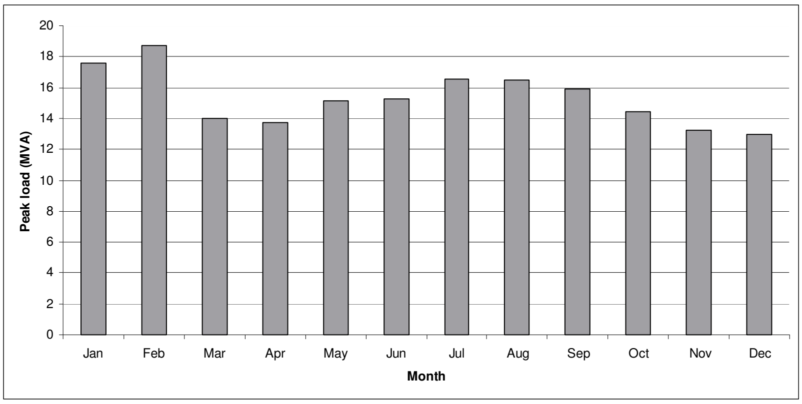


Figure 3-3 Typical CBD Monthly Peak Load Profile

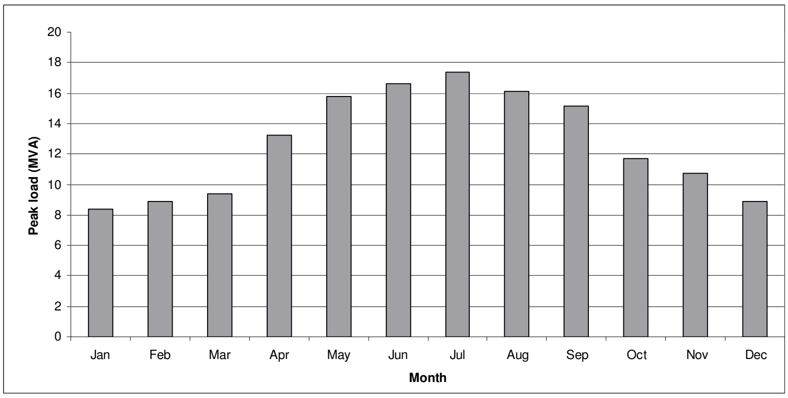


Figure 3-4 Typical Residential Monthly Peak Load Profile

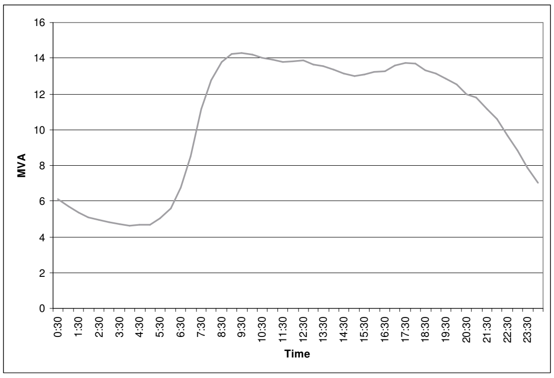


Figure 3-5 and 3-6 Typical CBD (L) and Residential (R) Daily Load Profile

3.3. Network Configuration and High Level Asset Description

Any electricity distribution system can be broadly categorised into primary and secondary assets. The primary assets carry the energy that is distributed to consumers, typically at higher voltages and currents. The secondary assets are an integral part of the distribution system and support the operation of the primary assets and include protection and control equipment, as well as communications systems.

3.3.1. Grid Exit Points

Wellington Electricity's network is supplied from the Transpower owned national transmission grid through nine grid exit points (GXPs), as shown in Figures 3-7 to 3-10. Central Park, Haywards and Melling supply the network at both 33 kV and 11 kV, and Kaiwharawhara supplies at 11 kV only. The remaining GXPs (Gracefield, Pauatahanui, Takapu Rd, Upper Hutt and Wilton) all supply the network at 33 kV only. The GXPs are described in more detail below.

3.3.1.1. Upper Hutt

Upper Hutt GXP comprises a conventional arrangement of two parallel 110 / 33 kV transformers nominally rated at 37 MVA each. Maximum demand on the Upper Hutt GXP in 2012 was 31.0 MVA. Upper Hutt GXP supplies Maidstone and Brown Owl zone substations via duplicated 33kV underground circuit connections. The 33kV bus at Upper Hutt has been included in the outdoor to indoor conversion programme by Transpower and this work is forecast to occur in 2015.

3.3.1.2. Haywards

Haywards GXP comprises an unconventional arrangement of one 110/11kV transformer nominally rated at 20 MVA feeding an 11kV point of supply at the Haywards site, and one 110/33 kV transformer nominally rated at 20 MVA supplying Trentham zone substation via duplicate 33kV connections. The maximum demand at the 11kV and 33kV busses in 2012 were 21.5 MVA and 14.9 MVA respectively. A 5MVA transformer supplies the Haywards local service switchboard and also links the 33 and 11kV switchboards.

3.3.1.3. Pauatahanui

Pauatahanui GXP comprises a conventional arrangement of two parallel 110 / 33 kV transformers nominally rated at 20 MVA each. Maximum demand on the Pauatahanui GXP 2012 was 19.5 MVA. This is within the transformers 22 MVA cyclic rating, however load growth in this area is relatively strong and

Wellington Electricity will review the adequacy of the existing arrangement within the planning period. Pauatahanui GXP supplies Mana and Plimmerton zone substations via single 33kV overhead circuit connections. Note that these two zone substations are linked at 11kV providing a degree of redundancy should one of the 33kV connections be out of service.

3.3.1.4. Takapu Road

Takapu Road GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 90 MVA each. Maximum demand on the Takapu Road GXP in 2012 was 92.0 MVA. Takapu Road GXP supplies zone substations at Waitangirua, Porirua, Tawa, Kenepuru, Ngauranga and Johnsonville via duplicated 33kV connections. These circuits leave the GXP as overhead lines across rural land and become underground at the urban boundary.

A review is planned for the Takapu Road GXP to consider how future load growth may be accommodated and whether the existing arrangement will provide the security appropriate for the Wellington Electricity network in the future. Transpower has advised that Takapu Road will be included in the second tranche of outdoor-indoor 33kV bus conversions to take place within the short term (forecast for 2015). Wellington Electricity is in discussion with Transpower about its requirements as a result of this upgrade.

3.3.1.5. Melling

Melling GXP comprises two parallel 110/33kV transformers nominally rated at 50 MVA each supplying zone substations at Waterloo, Naenae and Petone via duplicated 33kV underground circuit connections. It also accommodates an 11kV point of supply fed via two parallel 110/11kV transformers nominally rated at 25 MVA each, with a 32MVA cyclic rating following a protection constraint being addressed. Maximum demand on the Melling GXP in 2012 (including both 33kV and 11kV busses) was 69.2 MVA.

Melling GXP is located within a flood zone of the Hutt River and in recent times there have been two floods that caused damage at this site. Transpower redeveloped the site and moved all sensitive equipment, including the POS 11kV switchgear into a raised building. A flood barrier was erected to deflect floating debris away from Transpower's switchyard. Unfortunately this barrier will deflect debris into Wellington Electricity owned equipment such as 33kV cable risers and the Melling ripple plant (which may also be submerged in high water). Wellington Electricity has raised this issue with Transpower and together the risks at this site are being reviewed. The companies are also identifying and evaluating solutions to this problem including, if necessary, relocation of the Wellington Electricity owned ripple equipment and extension of the flood barrier.

3.3.1.6. Gracefield

Gracefield GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 85 MVA each. Maximum demand on the Gracefield GXP in 2012 was 51.8 MVA. Gracefield GXP supplies Seaview, Korokoro, Gracefield and Wainuiomata zone substations via duplicated 33kV connections. There are no issues with the Transpower owned assets at Gracefield GXP at present.

3.3.1.7. Kaiwharawhara

Kaiwharawhara is an 11kV point of supply where Wellington Electricity takes bulk 11kV supply from Transpower and distributes this via a Wellington Electricity owned switchboard within the GXP.

Kaiwharawhara is supplied at 110kV via Transpower owned circuits from the Wilton GXP, and has two 20/40MVA transformers in service. These assets are owned by Transpower.

Kaiwharawhara supplies load at the northern end of the Wellington CBD such as Thorndon and surrounds, and also light commercial and residential load around Ngaio Gorge and Khandallah areas.

Maximum demand at Kaiwharawhara in 2012 was 35.0 MVA.

3.3.1.8. Central Park

Central Park GXP comprises three 110/33kV transformers, T5 (120 MVA), T3 and T4 (100 MVA units) supplying a 33kV bus. There are also two Transpower owned 33/11kV (25 MVA) units supplying local service and an 11kV point of supply to Wellington Electricity. Maximum demand at Central Park GXP in 2012 was 171.4 MVA, which is well within the N-1 rating of the supply transformers. However, due to not having a 110kV bus, should a contingency occur at times of high load that results in the loss of a 110kV infeed (i.e. a circuit or transformer outage), the loading is constrained due to System Operator rules by the rating of the remaining banks, i.e. 109 MVA. As a temporary measure, a Special Protection Scheme has been installed by Transpower, however a permanent solution to the issue will be required as around 50MW of CBD load is at risk and cannot be supported by adjacent assets. This is discussed further in Section 5 (Network Planning).

3.3.1.9. Wilton

Wilton GXP comprises two 220/33kV transformers operating in parallel, supplying a 33kV bus that feeds to zone substations at Karori, Moore Street, and Waikowhai Street. These transformers are nominally rated at 100 MVA each, and the maximum demand in 2012 was 52.0 MVA. Transpower has advised that the 33kV outdoor bus will be moved indoors as part of their policy replacement programme and that this work has been brought forward to 2014 to accommodate the connection of another party's asset.

3.3.2. Embedded Generation

The network currently has a range of connected embedded generation including a number of connections of less than 10kW (typically residential), two landfill sites greater than 1 MW and a hospital with synchronised generation of approximately 8 MW. In addition, there are a number of customers with standby generation plant of varying sizes (typically less than 1 MW) which generally cannot be synchronised to the network.

Meridian Energy has recently obtained resource consent for the Mill Creek wind farm in the Ohariu Valley area which has a capacity of around 60 MW. Any connection to the Wellington network, or shared connection points, would be at 33kV or higher and will not affect Wellington Electricity's distribution network.

A wind farm with an installed capacity of approximately 8 MW, located on the south coast of Wellington has been consented but development has halted for the time being. Wellington Electricity had previously worked with the wind farm developer on options for providing a connection into the 11kV network. This connection requirement may arise again in the short to medium term.

The Wellington Regional council has commissioned a number of small scale hydro generation plants at existing water facilities storage and pumping facilities around the region. These are in the order of 1 MW each.

3.3.3. Subtransmission

The 33kV subtransmission system is comprised of assets that take supply from the Transpower GXPs and feed a total of 28 Wellington Electricity zone substations, incorporating 54 33/11kV transformers. This 33kV system is radial with each feeder supplying its own dedicated power transformer, with the exception of Tawa and Kenepuru where two feeders supply four transformers (one feeder shared per bank at each substation). All 33kV feeders supplying zone substations in the Wellington area are underground while those in the Porirua and Hutt Valley areas are a combination of overhead and underground. The total length of the 33kV system is 205 km, of which 147 km is underground.

All zone substations have N-1 subtransmission supply at 33kV, generally with one supply from each side of a Transpower bus (where available). Plimmerton and Mana each have a single 33kV supply to a single power transformer, however they are connected together on the 11kV bus, and as a result they operate as an N-1 substation with a geographic separation of 1.5 km. At certain times the 11kV bus tie cable can be constrained, although load control and 11kV network switching can alleviate this constrain. More detail on this is provided in section 5 (Network Planning).

A list of each zone substation’s capacity, incorporating 33kV cables and transformers, is provided in the section on demand forecasts.

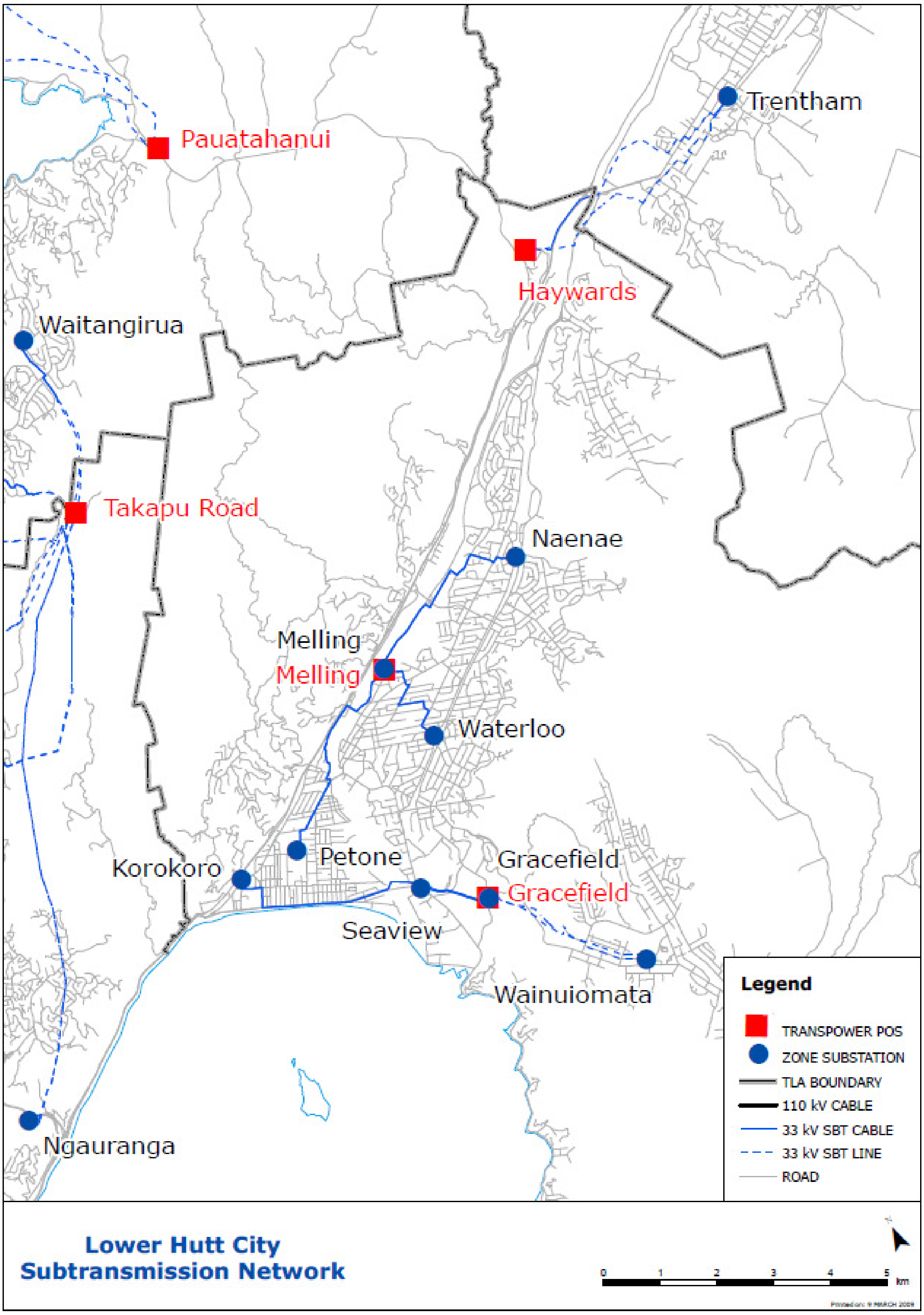


Figure 3-7 Lower Hutt Subtransmission Network

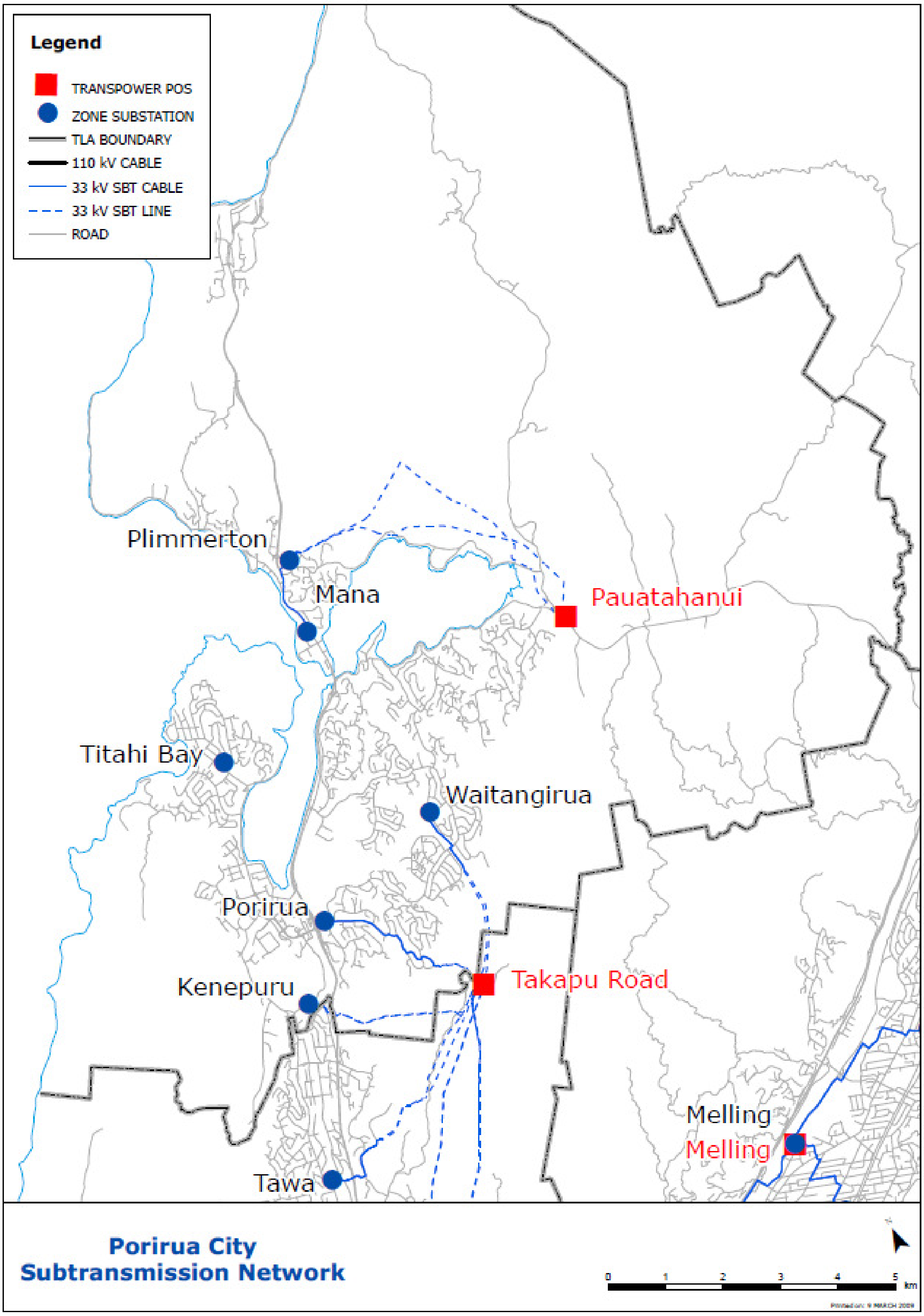


Figure 3-8 Porirua City Subtransmission Network

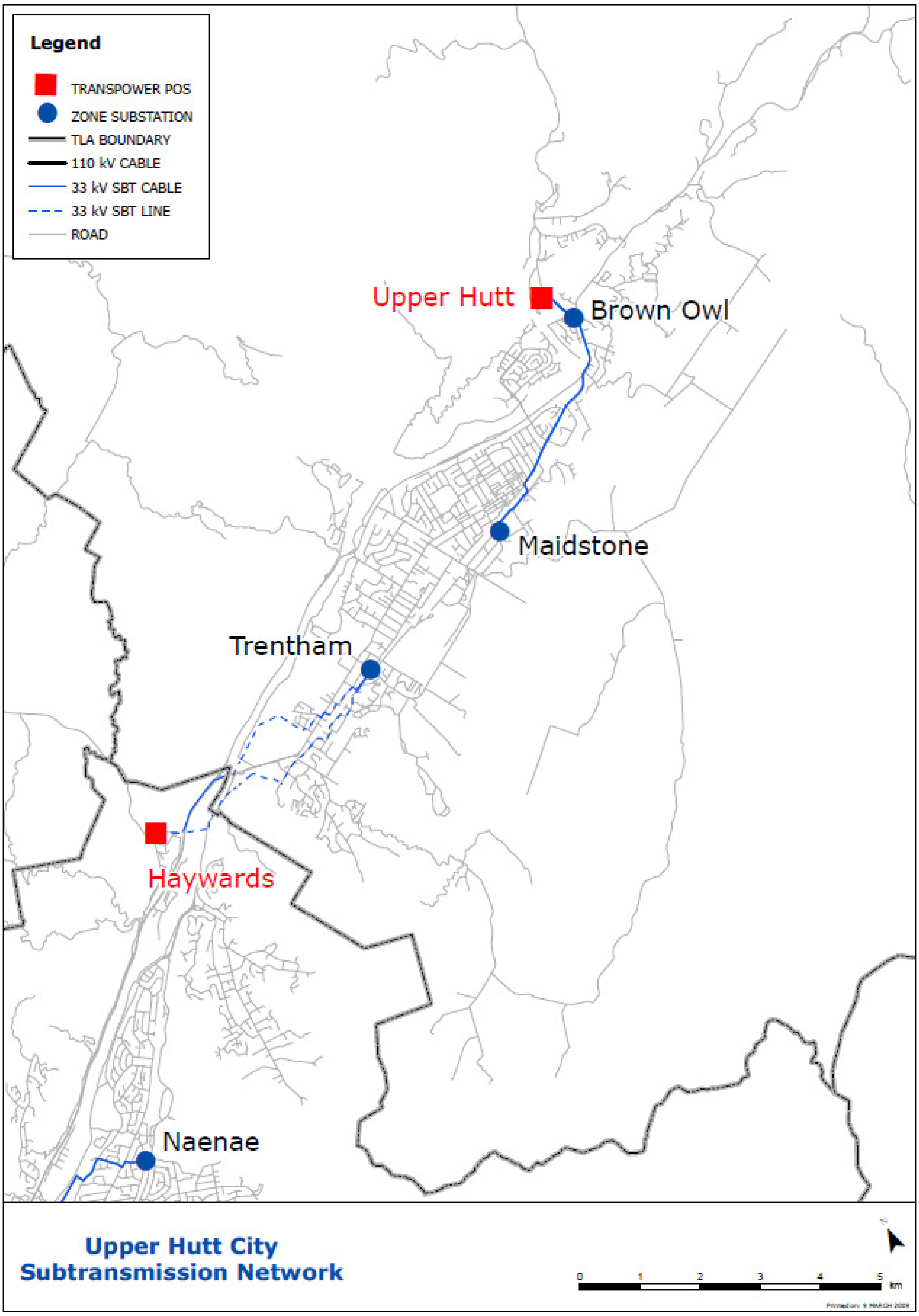


Figure 3-9 Upper Hutt City Subtransmission Network

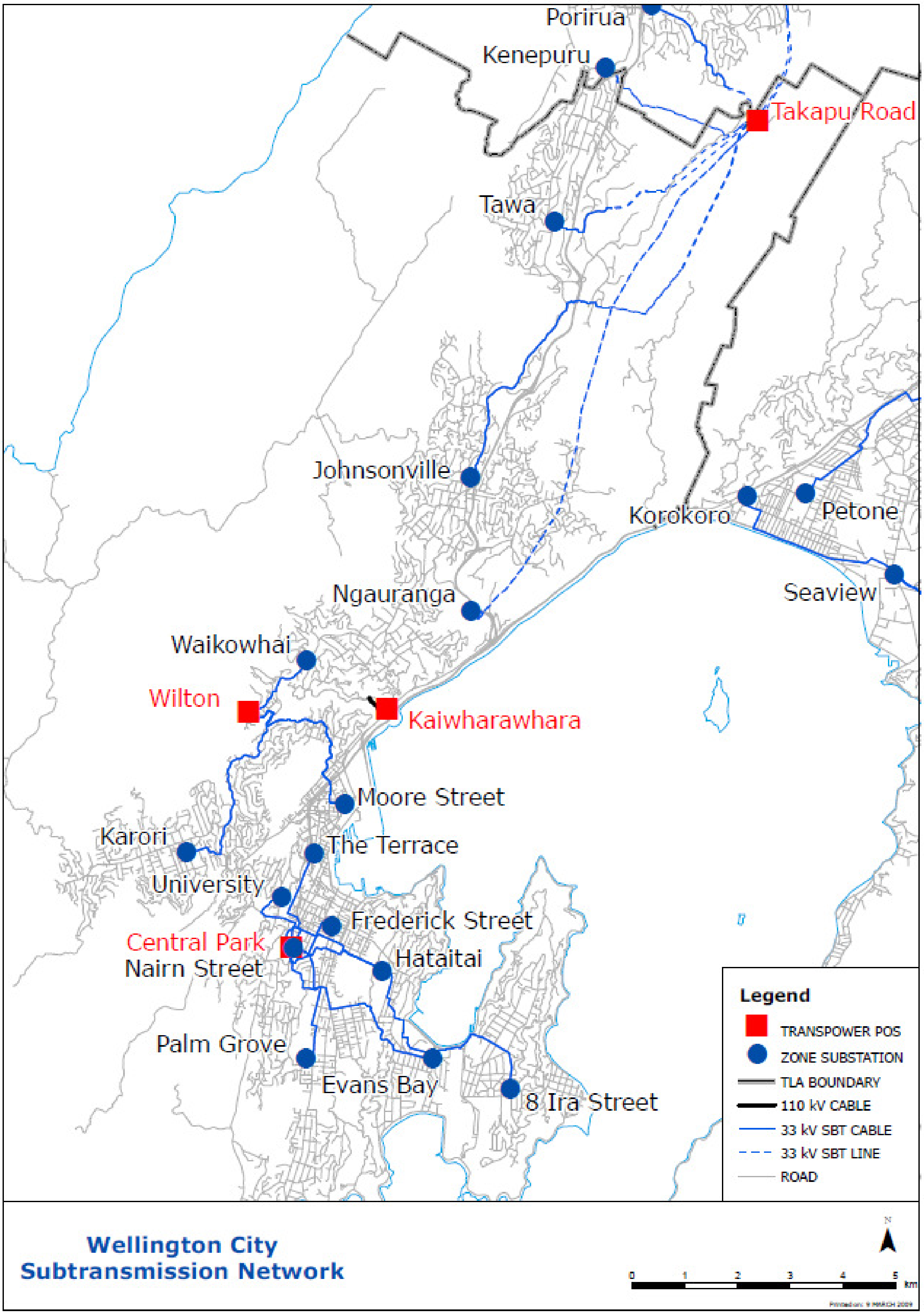


Figure 3-10 Wellington City Subtransmission Network

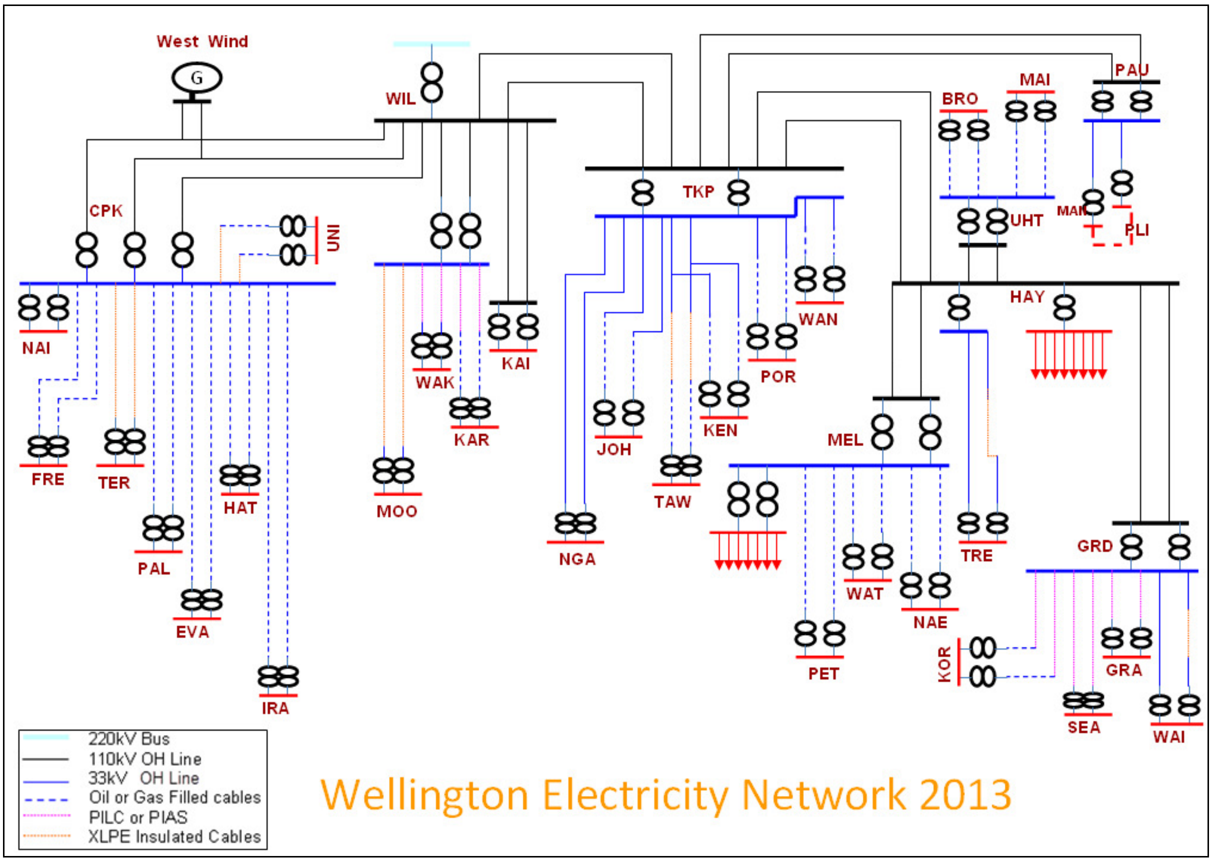


Figure 3-11 Overview of Wellington Electricity Network Connectivity

3.3.4. Distribution System

The 11kV distribution system is supplied from the zone substations, or directly from the grid supply point in the case of the 11kV supply points at Central Park, Melling, Haywards and Kaiwharawhara. While some larger consumers are fed directly at 11kV, the system mainly supplies approximately 4,230 distribution substations (11kV/415V) located in commercial buildings, industrial sites, kiosks, berm-side and on overhead poles. The total length of the 11kV system is approximately 1,740 km, of which 66% is underground. In Wellington City, the 11kV network is largely underground whereas in the Hutt Valley and Porirua areas there is a higher proportion of overhead 11kV lines. The varying proportions of overhead and underground distribution on the different parts of the system reflect the different design philosophies of earlier network owners, as well as geography of the various areas.

Most of the 11kV feeders in the Wellington CBD[2] are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of security and hence a high level of supply reliability. Most of the 11kV network outside the Wellington CBD, both in the Wellington City and Hutt Valley areas, comprises radial feeders with a number of mid feeder switchboards with circuit breakers and normally open interconnectors to other feeders so that, in the event of an equipment failure, supply to customers can be switched to neighbouring feeders. To allow for this, distribution feeders are not operated at their full thermal rating under normal system operating conditions.

[2] The CBD area is considered to be the commercial areas supplied by Frederick St, Nairn St, University, The Terrace, Moore St and Kaiwharawhara GXPs.

There are approximately 1,840 11kV circuit breakers operating within the distribution system. Around 370 of these are located at the zone substations and control the energy being injected into the distribution system. The remainder are located within distribution substations, mostly situated within or close to the Wellington CBD or in the Wellington City area, and allow the primary feeders in their respective areas to be operated in a closed loop arrangement. These circuit breakers are used to automatically isolate a faulted section of the network and to improve the ability to maintain an uninterrupted supply to all customers not directly connected to the faulted section. This is subject to cables having sufficient rating to carry extra load to support these contingent events.

The number of circuit breaker used in the distribution network is high in relation to other networks in New Zealand as illustrated in Figure 3-12.

Network	ICP count (approx.)	CB count (approx.)	ICP/ CB ratio (approx.)
Vector Networks	520,000	1,550	330
Orion NZ	190,000	800	240
Wellington Electricity	**164,750**	**1,840**	**90**
Unison	107,000	270	400
WEL Networks	84,000	380	220
Aurora Energy	81,000	400	200
Northpower	53,000	200	260

Figure 3-12 Comparison of Number of Circuit Breakers in Various Networks

The high number of circuit breakers in the Wellington Electricity network is a result of historic design practices aimed at delivering a very reliable network. The present network configuration is reviewed from time to time to consider the opportunity for further system optimisation as equipment condition determines the need for replacement. Wellington Electricity aims to maintain an equivalent service level for an area at the time of equipment renewal or network reinforcement and therefore may replace circuit breakers in parts of the distribution network where the existing architecture makes use of mid-feeder circuit breakers. The economics for smart network developments will be considered based on a fair return for the investment in line with the improved customer services.

3.3.5. Distribution Substations

Throughout the distribution network there are approximately 4,230 distribution substations sites (3,530 owned by Wellington Electricity as standalone sites and 700 housed on consumer sites) with around 4,280 associated distribution transformers in service, as some sites have multiple transformers installed. Pole-mounted distribution transformers are typically less than 150kVA and are generally simple platform structures or hanging bracket type arrangements. Ground-mounted distribution substations include a range of designs from the more significant reinforced concrete block buildings that can accommodate single transformers (typically a switch unit and low voltage (LV) distribution panel or frame) up to larger style three-transformer, multiple circuit breaker (CB) switchboards and extensive LV distribution framing. The more compact substations are generally the kiosk style, with an LV frame, transformer and ring main unit enclosed in a metal canopy. Other common styles are stand alone, open fenced enclosures or fully enclosed within customer owned buildings. New substation types are either metal canopy, pole mounted in rural areas, or indoor substations where the customer provides accommodation within a new or modified building.

In Wellington city the majority of the distribution transformers are ground mounted. The Hutt and Porirua areas are a combination of ground mounted and overhead installations. Individual capacities range from 5kVA to 2,000kVA and the weighted average capacity is approximately 300kVA.

Enclosure type	Quantity
Outdoor cage	276
Indoor	971
Padmount	1,157
Pole	1,822

Figure 3-13 Overview of Distribution Substation Types

3.3.6. Low Voltage Lines and Cables

Low voltage lines and cables are used to connect individual customers to the low voltage network supplied from the distribution transformers. The total system length is around 2,680 circuit-km, of which approximately 59% is underground.

Consumers are supplied via a low voltage fuse, which is the installation control point (ICP) used by the network to connect the consumer installation. This fusing is either an overhead pole fuse or located within a service pillar or pit near the consumers' boundary. Some other styles of fuse installation exist, however these are being progressively replaced following faults or when work is required on them.

In addition to service pillars there are approximately 400 link pillars on the network that allow isolation, reconfiguration and back feeding of certain LV circuits. These vary in age and condition and are being replaced in situations where their condition is poor and where they provide operational flexibility, or where the type of load served is sensitive to outages on the low voltage network, and back feeding will ensure compliance with service levels. In some cases, the LV network configuration has changed and there is no longer a requirement for a link pillar and they are removed if they have become unserviceable.

3.3.7. Secondary Systems

3.3.7.1. Protection Assets

Protection assets are used to automatically detect thresholds that indicate a potential equipment fault and to automatically issue control signals to disconnect faulted equipment. This ensures that the system remains safe, that damage is minimised, and also limits the number of consumers affected by an equipment failure.

On the HV system, there are more than 1,200 protection relays in operation. Around 95% are older electromechanical devices. The remainder are newer relays that use solid state electronic and microprocessor technology. Relays are generally mounted as part of the substation switchboard and are normally changed at the time of switchgear upgrade. At distribution level, 11kV fuses are used for protection of equipment.

On the LV system, fuses are used for the protection of cables and equipment.

3.3.7.2. Supervisory Control and Data Acquisition (SCADA)

The SCADA system is used for real time monitoring and to provide an interface to operate the network. SCADA can monitor and control the operation of primary equipment at the zone substations and larger distribution substations, as well as providing status indications from Transpower owned assets at GXPs. It is used to:

- Monitor the operation of the network from a single control room by remotely indicating key parameters such as voltage and current at key locations
- Permit the remote control of selected primary equipment in real time
- Graphically display equipment outages on a dynamic network schematic
- Transmit system alarms to the controller for action.

System information is collected by remote terminal units (RTUs) at each substation and is transmitted to a central master station located at the Haywards substation through dedicated communication links. Control signals travel in the opposite direction over the same communications links.

3.3.7.3. Load Control

Wellington Electricity uses a ripple injection signal load control system to control selected loads at consumer premises such as water heating and storage heaters, to control street lighting and also to provide some tariff signalling as required by retailers using the network. Starting in April 2012, Wellington Electricity has offered a controlled rate tariff specially for electric vehicle (EV) charging. This will be controlled using conventional ripple signals with the addition of an EV channel. The system is automatically operated by the master station located at Haywards, and from a user terminal at the Network Control Room at Petone, to control loads at peak times. Load control is fundamental to the operation of an optimised distribution network.

3.3.7.4. Communication

Operation of secondary systems requires the use of high security communication links between the master station and the different control points. Like most distribution businesses, Wellington Electricity operates its own communications system with a small number of communications links being leased from service providers such as Telecom, Vector Communications and Transpower.

Wellington Electricity's own network comprises mainly copper pilot cable with a small amount of fibre-optic and UHF radio infrastructure. Communications links leased from other service providers are either fibre-optic or radio links.

3.4. Categories of Assets and Age Profiles

3.4.1. Subtransmission Cables and Lines

3.4.1.1. Subtransmission Cables

Wellington Electricity owns approximately 145km of subtransmission cables operating at 33kV. These cables comprise some 52 circuits connecting Transpower GXPs to Wellington Electricity's zone substations. Around 25 km of subtransmission cable is of XLPE construction and requires little maintenance. The remainder is of paper insulated construction, with a significant portion of these cables being relatively old pressurised gas or oil filled with either aluminium or lead sheath. A section of the subtransmission circuits supplying Ira St zone substation are fluid filled PIAS cables with copper conductors rated for 110 kV but operating at 33 kV. The lengths, age profile and spare holdings of this asset class are shown below.

Construction	Design voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33kV	29%	42 km
Paper Insulated, Gas Pressurised	33kV	41%	60 km
Paper Insulated	33kV	6%	9 km
XLPE Insulated	33kV	18%	25 km
Paper Insulated, Oil Pressurised	110kV	6%	9 km

Figure 3-14 Summary of Subtransmission Cables

There are also 33kV rated oil cables supplying the Titahi Bay switching station from Porirua zone substation which are operated at 11kV. These are not counted in the subtransmission circuit length. These cables could in future be energised at 33kV if Titahi Bay was developed into a full substation and operated as subtransmission cables, although the likelihood of this occurring is low. Elsewhere in the network, there are abandoned 33kV cables being run at 11kV that will not be used as subtransmission again.

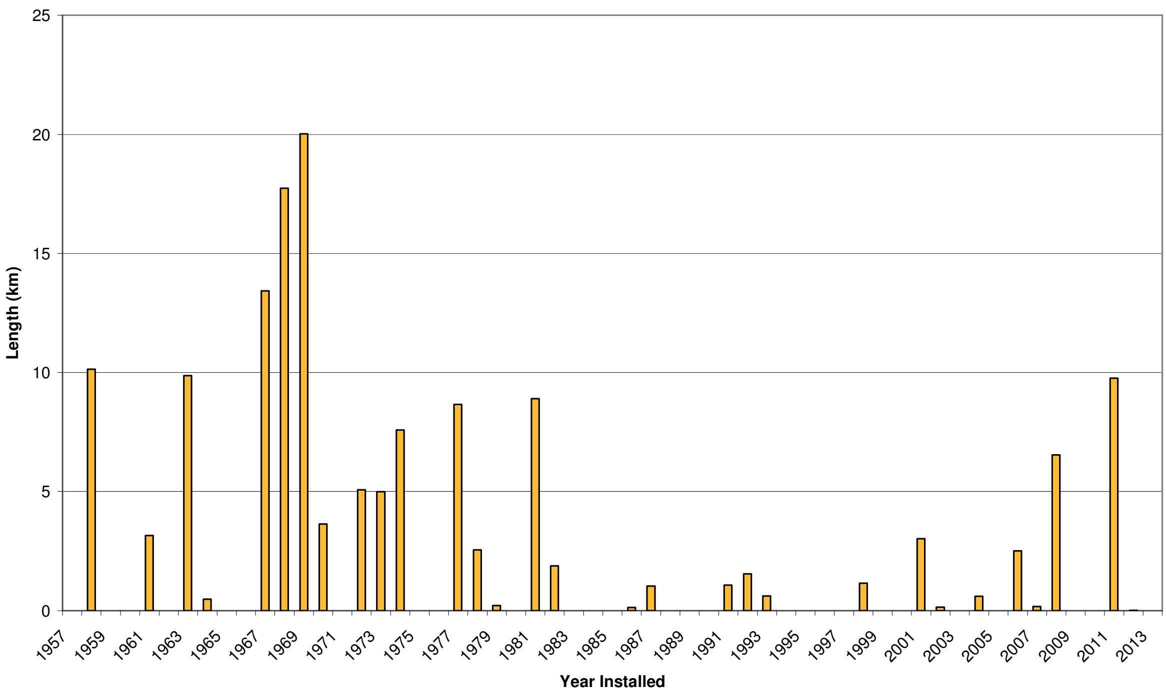


Figure 3-15 Age Profile of Subtransmission Cables

Strategic Spares	
Medium lengths of cable	It is necessary to hold medium lengths of oil and gas cable in store to allow replacement of short sections following damage. By holding oil and gas cable lengths, the Field Service Provider is able to undertake repairs without requiring termination and transition to XLPE cable.

Strategic Spares	
Standard joint fittings	Stock is held by the Field Service Provider to repair standard oil and gas joints. These need to have a minimum stock level held. Where stock levels drop below minimum, replacement parts need to be sourced and if necessary be manufactured locally.
Termination/transition joints	Two gas to XLPE cable transition joints have been purchased and are held in storage to allow quick repair and alteration to gas cables using XLPE cables.

Figure 3-16 Spares Held for Subtransmission Cables

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.1.2. Subtransmission Lines

Wellington Electricity owns approximately 58km of subtransmission overhead lines operating at 33kV which connect Transpower GXPs to Wellington Electricity's zone substations. These lines are both timber and concrete pole lines with AAC conductor being the predominant type. Overhead line was typically used for subtransmission in the former Hutt Valley network for circuits from Takapu Rd, Pauatahanui and Haywards converting to underground cable at the urban boundary. Subtransmission overhead lines are typically located on rural or sparsely developed land, although sometimes in locations with difficult or four wheel drive access only.

Category	Quantity
33kV Overhead Line	58 km

Figure 3-17 Summary of Subtransmission Lines

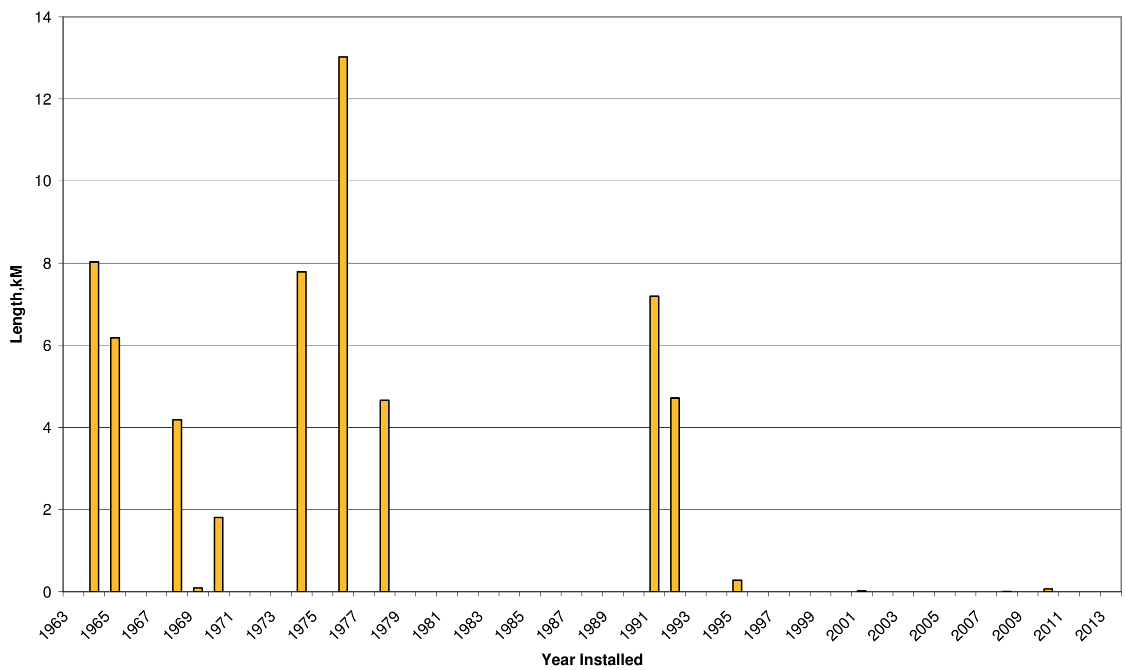


Figure 3-18 Age Profile of Subtransmission Lines

3.4.2. Zone Substation Buildings

Wellington Electricity has close to 500 substation buildings on the network. There are 30 major substation buildings, 28 of which are located at zone substation sites and 2 at major switching stations. The buildings typically stand alone (although some in the CBD are close to adjacent buildings, or in the case of The Terrace located in the basement of a hotel) and have switchgear, protection equipment, local AC and DC supplies installed inside. Some buildings also contain transformers and ripple injection plant. Wellington Electricity also has a large number of kiosk type distribution substations. These are covered separately later in this section as they form part the distribution substation asset class. The age profile of zone substation buildings is shown below.

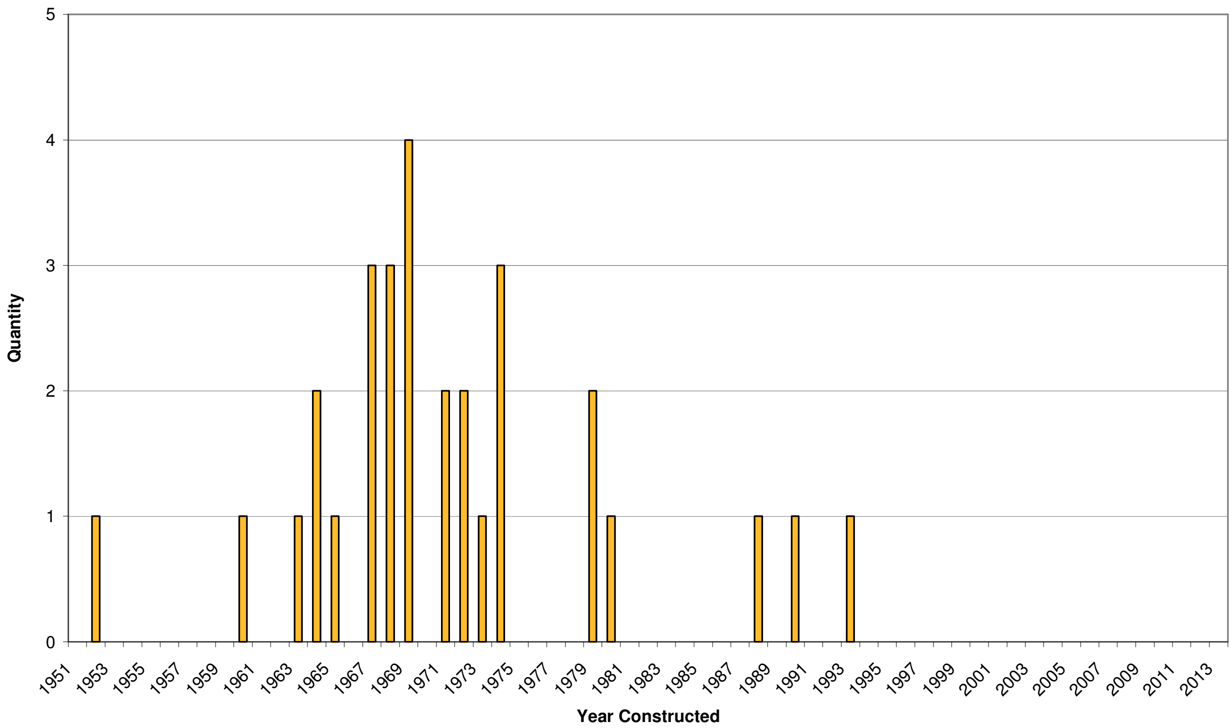


Figure 3-19 Age Profile of Zone Substation Buildings

The average age of the buildings is 41 years and they are in good condition, however from time to time require maintenance or replacement of some components such as doors, roofs and spouting. Wellington Electricity is required to undertake seismic strengthening activities on buildings as required by the local councils on some of the older buildings constructed prior to 1976. A seismic review and assessment has been undertaken on the majority of zone substation buildings. Remedial work has been undertaken as a result of this review, including securing plant inside substations.

In some cases, Wellington Electricity does not own the land under the zone substation and has arrangements in place for a long term lease with the landowner.

Full details of maintenance and refurbishment are covered in Section 6 (Lifecycle Asset Management).

3.4.3. Zone Substation Transformers

Wellington Electricity has 54 33/11kV power transformers in service on the network. All zone substation transformers are operated well within their specified ratings, are regularly tested and have condition assessments undertaken. Overall the transformer fleet is in a generally sound condition even though a number of transformers are reaching their end of design life of 55 years. However, based on their operating conditions and maintenance, it is expected that most transformers will continue to operate beyond their design life. Nevertheless older transformers require more intensive monitoring to assess and evaluate their condition. Estimated DP tests[3] on the transformers completed in 2009, using the Furan analysis method, indicate a high level of remaining life given the age. Whilst not as conclusive as taking internal paper samples, this is a good indicator of internal condition. Mechanical deterioration is an issue that needs to be monitored on older units, both for condition of external fittings, as well as internal components such as tap changer contacts and mechanisms.

The age profile for zone substation transformers is shown below.

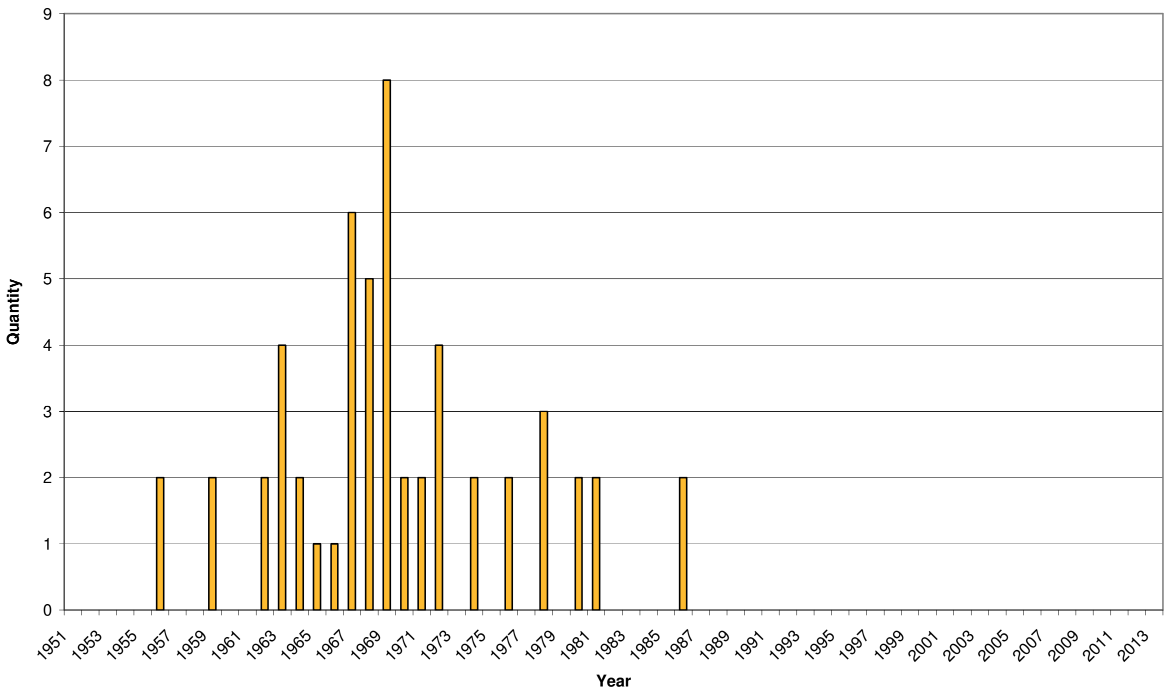


Figure 3-20 Age Profile of Zone Substation Transformers

The age profile indicates that the average age of the transformer fleet is high (around 42 years). Based on the assumption that zone transformers have a design life of around 55 years then all of the zone transformers have exceeded midlife and around 65% of transformers have exceeded an age of 42 years.

Wellington Electricity holds critical spares for the power transformers and tap changers in the system as detailed in the table below.

[3] Degree of Polymerisation, an indicator of dielectric strength of paper insulation.

Strategic Spares	
Tap changer fittings	Wellington Electricity holds a number of critical and maintenance spares for the tap changers on Zone substation transformers, typically contacts and related components. These components have high wear and are eroded by arcing during operations. The components held are for tap changers that have not had recent maintenance and are therefore used in the next maintenance cycle. Where excessive wear is noted during maintenance, spares are ordered and held in stock for that model of tap changer. Spares are available for most models that are operated on the network, and in some cases spares can be re-manufactured by third party suppliers.
Transformer misc. fittings	Various other transformer fittings have been identified and held for sites where having a transformer out of service for a prolonged period is unacceptable for minor repairs. Fittings include Buchholz relays, high voltage bushings etc. For major repairs a unit will be swapped out.
Spare transformers	There is one unit from Trentham that can be easily removed from service due to low loadings and ease of back feeding should a spare transformer be required. Should Wellington Electricity require a second spare transformer one of the units from Petone substation can be utilised. This area also has good 11kV backfeed options and low loadings. Trentham has external bushings and Petone has a cable box so there is a transformer for either situation. Other sites with low loading include Gracefield, Tawa and Kenepuru. In extreme cases, these sites can be evaluated for transformer removal.

Figure 3-21 Spares Held for Zone Substation Transformers

3.4.4. Substation DC Systems

The DC auxiliary systems provide power supply to the substation protection, control, metering, monitoring, automation and communication systems, as well as circuit breaker tripping and closing mechanisms. The standard DC auxiliary system comprises batteries, battery chargers, DC/DC converters and a battery monitoring system. Wellington Electricity has a number of different voltages: 24, 30, 36, 48, and 110V, largely for historical reasons, however has standardised on 24V for all new or replacement installations.

A range of spares is held, mostly chargers of different voltages that have been removed from sites over recent time. Batteries are available locally at short notice so these are not held.

3.4.5. Switchboards and Circuit Breakers

11kV circuit breakers are used in zone substations to control the power injected in to the 11 kV distribution network and also within the network to increase the reliability of supply in priority areas such as in and around the CBD. The largest single type is Reyrolle Pacific type LMT circuit breakers but other types are also in service in large numbers. There are approximately 1,840 circuit breakers forming 404 11kV switchboards on the Wellington Network.

An age profile of the circuit breakers and switchboards is shown below.

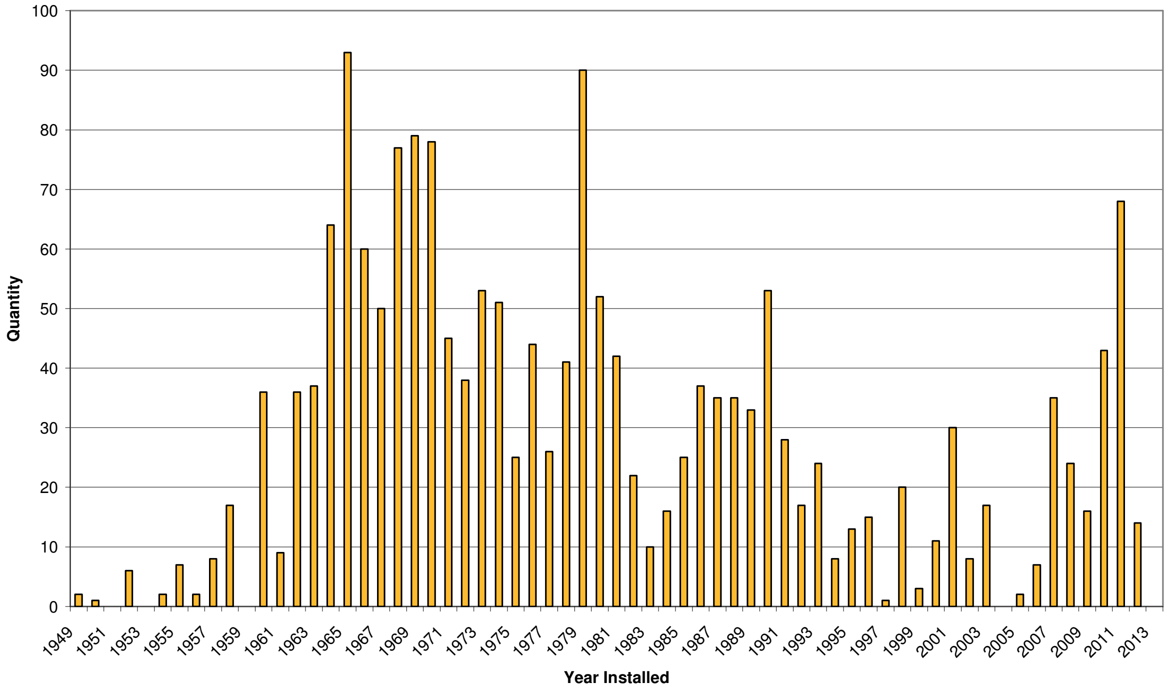


Figure 3-22 Age Profile for Circuit Breakers

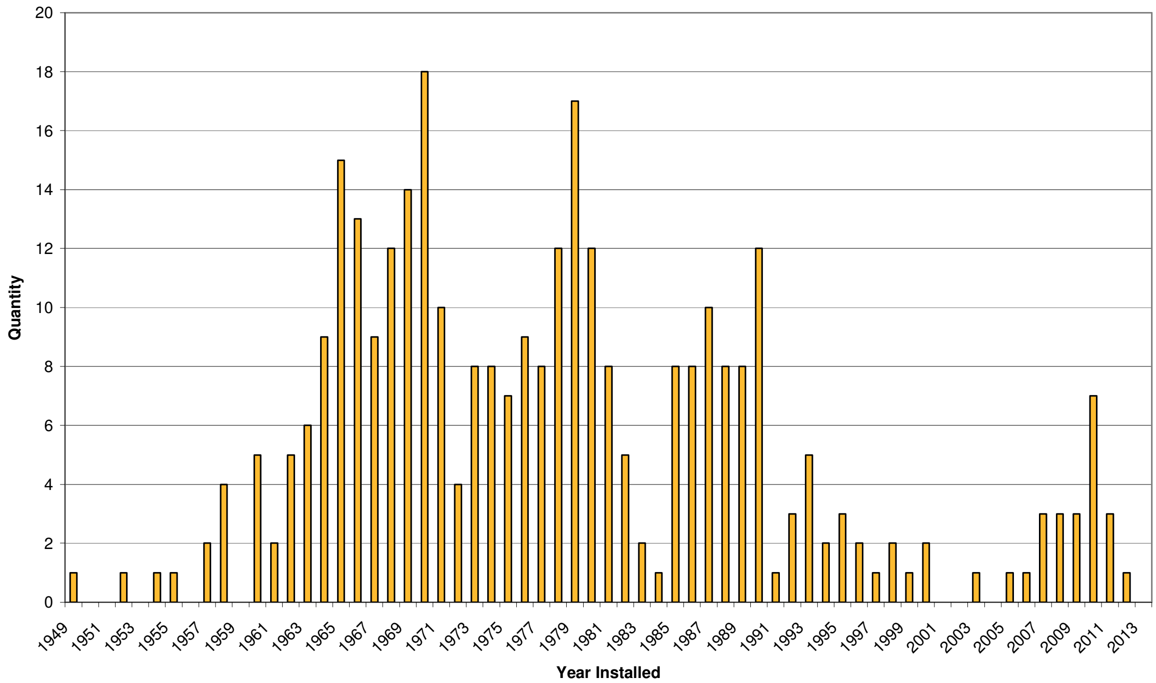


Figure 3-23 Age Profile for Switchboards

The age profile indicates that the average age of circuit breakers in the Wellington Network is around 31 years, with the age of individual breakers ranging from relatively new to more than 50 years. The mix of circuit breaker technologies reflects the age of the equipment. The oil type circuit breakers are the oldest in the network followed by SF_6 and vacuum type circuit breakers. Most circuit breakers are oil insulated with relatively intensive maintenance regimes.

There are two 33 kV oil circuit breakers at Ngauranga which have been in service at this site for approximately 20 years. Having been installed in 1993 when the substation was constructed, they were originally manufactured in the 1960s. A protection scheme proposed for the subtransmission circuits from TP Takapu Rd will see these being made redundant and all circuit breakers remaining will be 11kV. Certain oil-type circuit breakers are approaching or have passed the end of their design life of 40 years. Inadequate fault level rating, equipment failures, lack of spare parts, and increased maintenance costs compared to newer SF_6 or vacuum equipment are areas of concern for this aging equipment.

Category	Quantity
33kV Circuit Breakers	2
11kV Circuit Breakers	1,839

Figure 3-24 Summary of Circuit Breakers

Given the high number of circuit breakers in service on the Wellington network, it is important to keep adequate quantities of spares to enable fast repair of minor defects. Some types of circuit breakers, such as early Statter and AEI, have limited numbers of spares available however there are low numbers of these types installed on the system. There are large numbers of spares held for the Reyrolle type circuit breakers and this is reflective of the number in service.

Manufacturer	Quantity
ABB	43
AEI	81
BTH	51
Crompton Parkinson	2
GEC/Alstom	99
Holec	8
Merlin Gerin / Schneider	136
Reyrolle	1,143
Siemens	16
South Wales	36
Statter	58
Yorkshire	91
Not recorded	77
Total	**1,841**

Figure 3-25 Summary of Circuit Breaker by Manufacturer

The largest quantity of circuit breakers on the network, used predominantly at zone substations, is Reyrolle type LMT. The large numbers of spares held for the Reyrolle type circuit breakers is reflective of the number in service. In addition the RPS Switchgear (formerly Reyrolle Pacific) factory is located in Petone which means that spares above those normally held by the network are available within short timeframes if required for LMT type switchgear. At present no formal relationship exists between Wellington Electricity and RPS for spares provision, however this could be investigated further if required in future.

Strategic Spares	
Circuit breaker trucks	At least one circuit breaker truck of each rating (or the maximum rating where it is universal fitment) is held for each type of withdrawable circuit breaker on the network.
Trip/Close coils	Spare coils held for each type of circuit breaker and all operating voltages.
Spring charge motors	Spare spring charge motors held for each voltage for the major types of switchgear in service (Reyrolle C gear, LMT, etc).
Current transformers and primary bars	Where available, spare current transformers and primary bars should be held to replace defective units. In particular 400A current transformers for Reyrolle LMT as this type of equipment has a known issue for partial discharge.

Figure 3-26 Spare Parts Held for Circuit Breakers

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.6. Protection and Control Systems

Due to the closed-ring architecture of the central Wellington distribution network there are a large number of protection relays, the majority (close to 85%) of which are electromechanical type. Numerical type relays are the latest additions to the network but constitute only 10% of the population. Solid state or static type relays ranging in age from around 15 to 25 years represent around 5% of the total number of relays.

The average age of the protection relays on the Wellington network is around 33 years and it is estimated that around 400 or 30% of the protection relays are 40 years or over in age. Generally all protection relays are in good condition with the exception of PBO electro mechanical and Nilstat ITP solid state relays. These relays have performance and functionality issues, which had triggered an ongoing replacement programme under previous owners. The majority of PBO type relays were replaced in the old Hutt Valley area but few have been replaced in the Wellington City area.

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.7. SCADA

Wellington Electricity's SCADA master station is located at the Transpower-owned Haywards substation. It is a GE ENMAC system installed in 2009 which became fully functional in 2011. The GE ENMAC system replaced a Foxboro (formerly Leeds & Northrup (L&N)) LN2068 system which was initially installed in 1986 and which still provides some functionality with an automated load management package. The Foxboro system will be retained in the short term to provide the automatic load control function until the GE ENMAC system is upgraded to undertake this function, or an alternative standalone system is implemented. Wellington Electricity is investigating the replacement of the automatic load control system and an independent system may provide other benefits such as supporting demand-side management initiatives. Wellington Electricity has yet to fully explore the use and benefits from demand-side management initiatives beyond the traditional use of ripple load control on hot water storage. Proposed changes in the parties who may control load could reduce Wellington Electricity's ability to control load to manage peak demand and system security. This means that further assessment of the situation will be required before investment is made in new load control systems.

Data is communicated to the master station by remote terminal units (RTUs) that are located at the different control and monitoring sites. The age and technology of the RTUs vary and many are now obsolete. The protocols in use on the Wellington network are Conitel, DNP3.0 and IEC61850. Wellington Electricity has 250 RTUs installed in sites from GXP level down to small distribution substations. An age profile of SCADA RTUs is shown below.

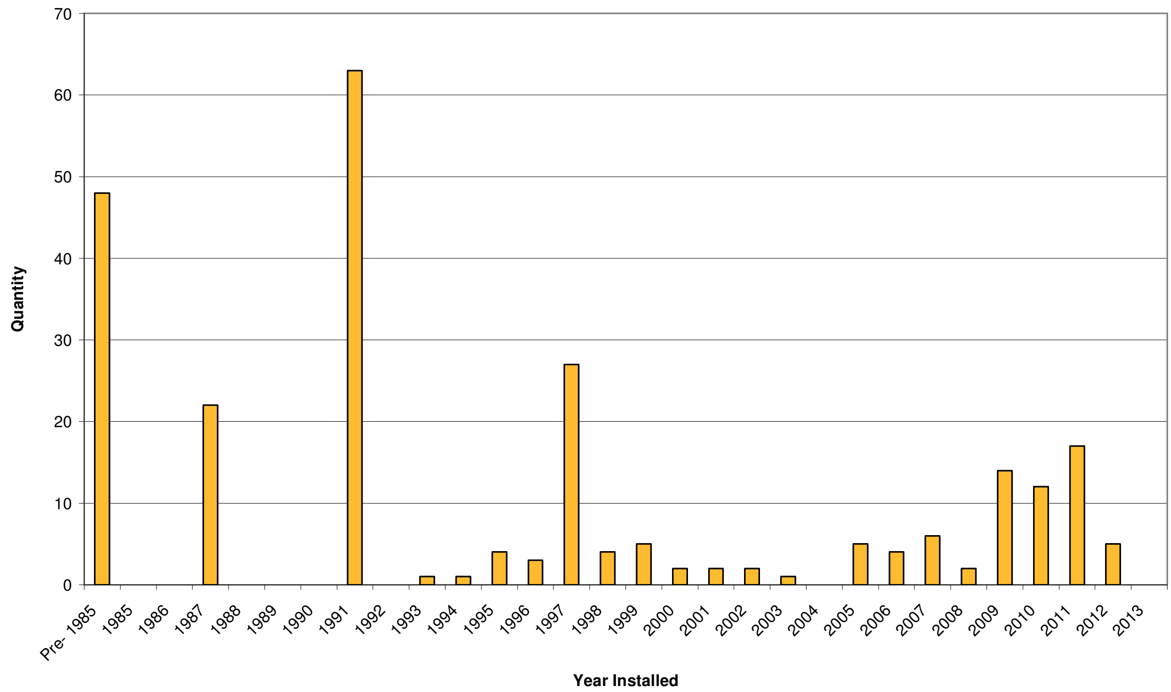


Figure 3-27 Age Profile of SCADA RTUs

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.7.1. Substation Level TCP/IP Communications

Presently the substation level TCP/IP (Transmission Control Protocol/Internet Protocol) network hardware and communications circuits are leased from external service providers. The contract with the main service provider for the TCP/IP network will expire in June 2013. At this point Wellington Electricity will take ownership of around 300 routers and other terminal equipment and review the commercial arrangements around use of the fibre circuits and communications equipment support. A draft communications strategy has been developed which outlines the forward view of the business for all communications, of which network substation communications is a major part. The renewal of the communications contracts in 2013 will be an outcome of this strategy. Finalisation of the communications strategy is expected during 2013 with details included in the 2014 AMP.

As substation sites are being upgraded or developed, and if IP network connections are available, the station RTU is upgraded and moved onto the substation TCP/IP network using the DNP3.0 protocol. Presently there are 44 sites (a mixture of zone and distribution substations) on the substation TCP/IP network.

There are two Siemens Power Automation System (PAS) units that act as a protocol converter between the Siemens IEC61850 field devices and that of the DNP3.0 SCADA master station. These units are designed to allow fail-over redundancy to prevent a single point of failure at the PAS. The use of the Siemens PAS unit was part of a previous network owner's protection and control strategy and Wellington Electricity has no plans to add further IEC61850 devices to the PAS system. The future of the PAS has been reviewed and it is proposed to install separate IP based RTUs at the three sites which utilise the Siemens PAS which will eliminate the reporting of multiple sites through to the PAS. This concept will be further developed during 2013 and is proposed that the work is undertaken during 2014 or 2015. As this is not confirmed, a project is not included in the forecast expenditure for future years.

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.8. Load Control Systems

Wellington Electricity uses a ripple injection signal load control system to inject 475Hz and 1050Hz signals into the network for the control of selected loads at consumer premises such as water heating and storage heaters, to control street lighting and also to provide some tariff signalling as required by retailers using the network. There are 26 ripple injection plants on the network and these are located at GXPs and zone substations. The Wellington city area has a 475Hz signal injected into the 33kV network with one plant per GXP and two plants injecting at Kaiwharawhara 11kV point of supply. The Hutt and Porirua areas have a 1050Hz signal injected at 11kV at each zone substation. All ripple injection is controlled by the master station at the Haywards Substation, however with supervisory control from the Petone Network Control Room. An age profile of ripple plant is shown below.

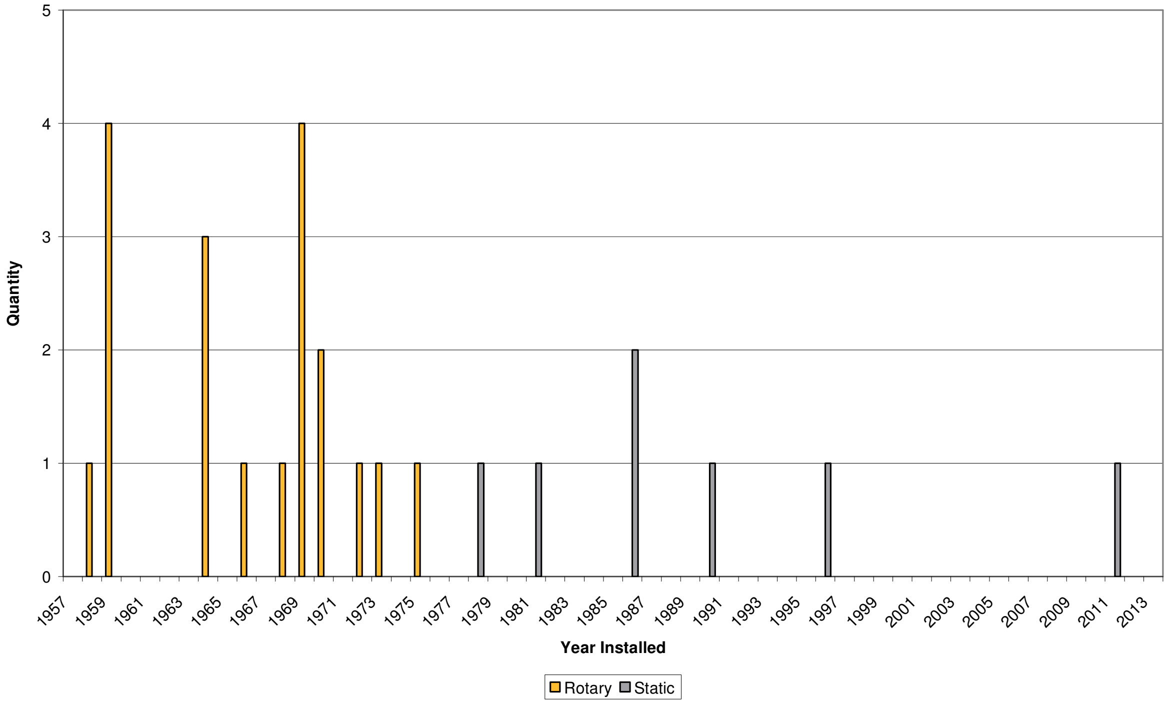


Figure 3-28 Age Profile of Ripple Plant

There is significant benefit in having a fully functional load control system and being able to control loads at peak times and to defer energy consumption by interruptible loads until times of lower demand on the system. This allows for better asset utilisation as the distribution network does not need to be oversized to allow for short duration peaks. Wellington Electricity does not own the ripple receivers installed at consumer premises and is experiencing decreasing levels of control as these devices fail and are not replaced. Over time the network will continue to preserve controllable load and look at alternatives with market participants and retailers to defer the need for investment in the distribution system. Wellington Electricity is encouraging retailers and metering providers to ensure investments and upgrades preserve the ripple control system due to its importance to managing loading on the network and transmission system. Wellington Electricity believes ripple control is the most cost effective technology for load control due to the existing installed base, and will continue to operate this system. Wellington Electricity also uses ripple control to participate in the Instantaneous Reserves market and for supporting the Transpower Automatic Under Frequency Load Shedding (AUFLS) system.

For more than 50 years the distribution network has been developed and sized on the basis of having a fully functioning load control system. Changes to the Electricity Authority's Model UoSA and the potential development of a market arrangement for load control will potentially lead to Wellington Electricity losing its ability to effectively control load on the network. The loss of this ability to move load, and the potentially decentralised control of it, could lead to negative outcomes such as overloading of system components, increased peak demands on assets and voltage and power quality complaints under some conditions due to high loadings.

If the market concept continues then protocols need to be established and enforced to make sure that controllable load "owners" don't create system issues through their actions or inactions. In the event that Wellington Electricity is unsuccessful in maintaining this ability to control load, it will need to adjust its load forecasts to contemplate the situation of no controllable load at peak times. This would see a significant increase in capital investment required which is not funded under the current pricing regime and excluded from current forecasts for capital investment in the network.

There are some small areas of network that receive DC bias load control signals, however these are being converted to ripple control where opportunities exist to do so.

Strategic Spares	
Injection plant	A spare rotary motor-generator set is held for the 11kV ripple system in the Hutt Valley area, rated at 24kVA. A spare solid state controller has recently been purchased to cover a failure at any of the four Wellington city locations. An assortment of capacitors and coupling cell equipment is held in store.
Controllers	A spare Load Control RTU Controller is kept as a strategic spare as the same type is used across the network.

Figure 3-29 Spares Held for Load Control Plant

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.9. Overhead Lines

The overhead lines in Wellington Electricity's network consist of 29% wooden and 71% concrete pole lines. There are a total of 52,700 poles in the network at present accommodating network assets or customer service lines. The total number of poles owned by Wellington Electricity is 36,440 poles. As Wellington Electricity did not purchase customer service lines, there is ongoing work required to advise customers of their responsibilities relating to these privately owned lines.

Pole Owner	Wood	Concrete	Total
Wellington Electricity	10,734	26,015	36,749
Customer / Telecom	11,839	2,275	14,114
Wellington Cable Car	1,230	607	1,837
Total	**23,803**	**28,897**	**52,700**

Figure 3-30 Summary of Poles

3.4.9.1. Poles

The average age of concrete poles is 26 years. Although the standard asset life for concrete poles is 60 years, there are a number of concrete poles that have been in service for longer than this. The average age of wooden poles is around 38 years of age and nearly 40% of all wooden poles are older than 45 years (the standard asset life of wooden poles). Crossarms are predominantly hardwood and are generally in a fair condition. Crossarms have a shorter life than poles, especially concrete poles, and will generally require replacement approximately half way through the life of the pole. An age profile of the poles on the network is shown below.

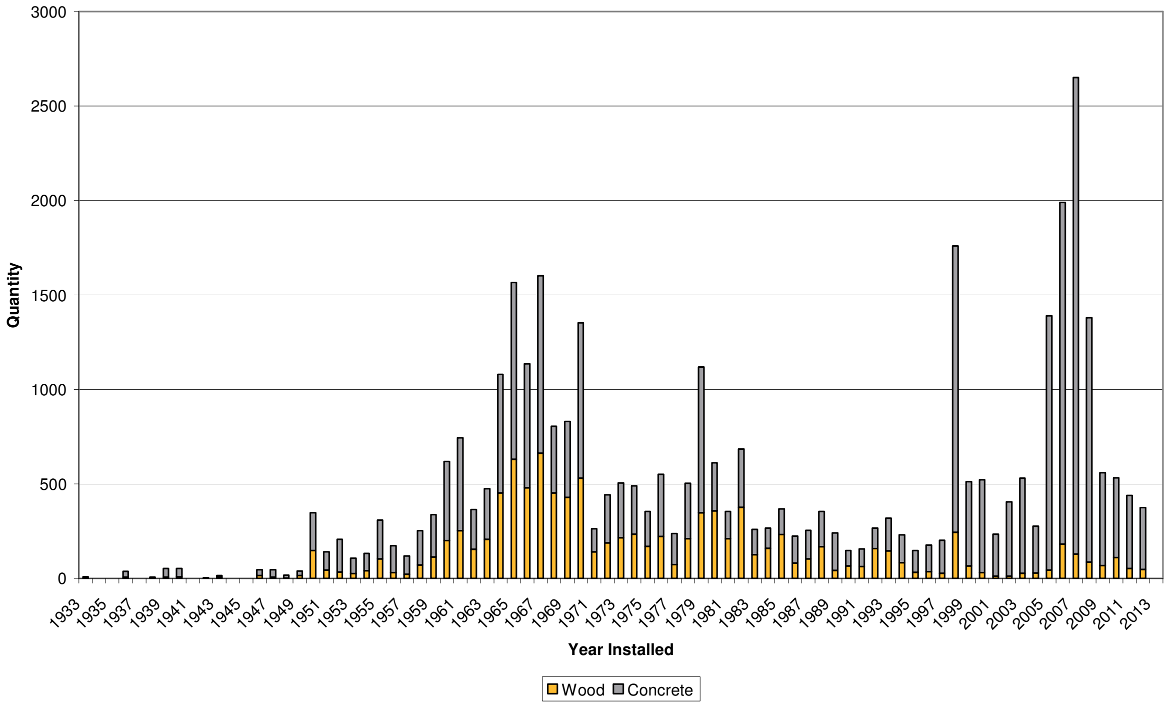


Figure 3-31 Age Profile of Poles

Along with Chorus (formerly Telecom) accessing the poles for their copper telephone services, a previous network owner entered into agreement with Saturn (now TelstraClear) to support cable TV circuits from the majority of the network poles across the region. This is causing problems for maintenance and operations due to congestion on the poles. Due to this congestion, Wellington Electricity must consider the impact and full life cycle costs of future access for wide scale attachment to poles. Each case will be evaluated on its own merits. Wellington Electricity and Chorus are now in discussion around the use of Wellington Electricity poles to support aerial service lines for the ultrafast broadband roll-out that Chorus is undertaking. These are proposed to be underground to overhead risers or road crossings only outside individual properties and, while not as problematic as circuits running along the lines, will impede access to poles for maintenance and replacement activities.

3.4.9.2. Lines/Conductor

Overhead conductors are predominantly all aluminium conductor (AAC), with older lines being copper (Cu), and in some areas aluminium conductor steel reinforced (ACSR), however this type was not widely used due to the high salt presence and corrosion in the Wellington area. New line reconstruction typically utilises all aluminium alloy conductor (AAAC). Where possible, low voltage aerial bundled conductor (LV ABC) and, to a lesser extent, covered conductor thick (CCT) for 11 kV lines are used in areas susceptible to tree damage. An age profile of overhead line conductors is shown below.

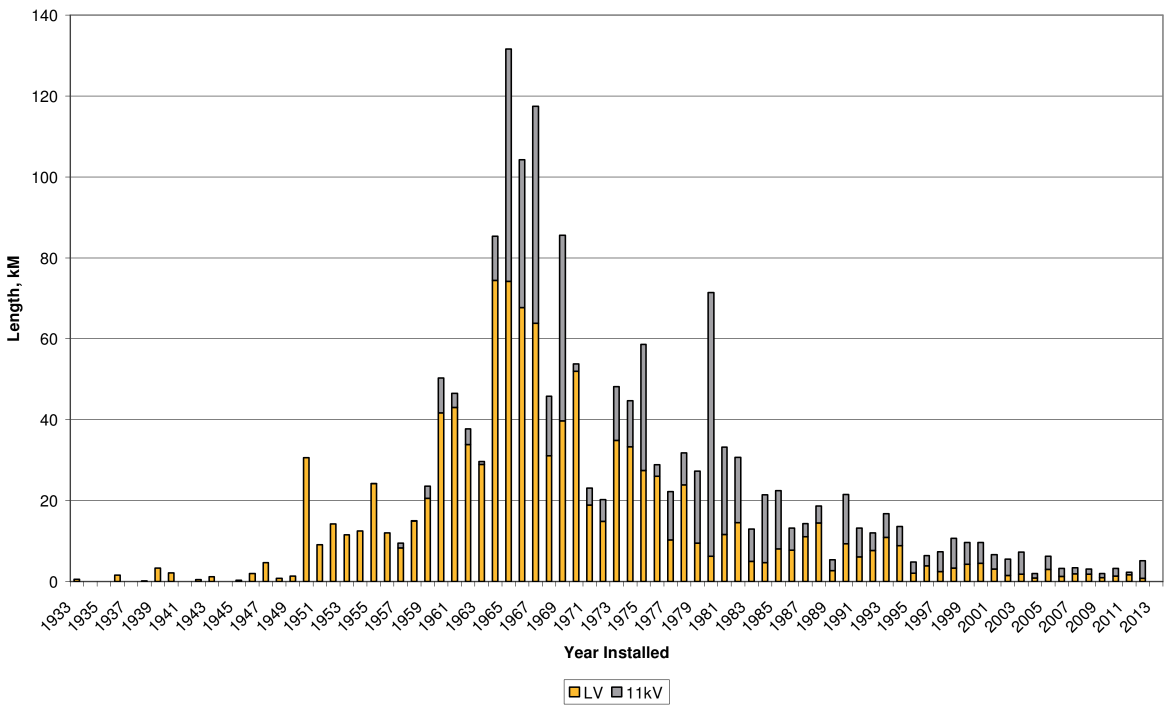


Figure 3-32 Age Profile of Distribution Overhead Line Conductors

Category	Quantity
11kV Line	598 km
Low Voltage Line	1,096 km

Figure 3-33 Summary of Distribution Overhead Lines

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.10. Overhead Switchgear and Devices

There are 306 air break switches (ABS), 25 auto-reclosers, 187 knife links, 52 gas insulated overhead switches and a mix of expulsion type drop out fuses for breaking the overhead network into sections.

Most of the ABSs are more than 20 years old, are not cost effective to refurbish and range from fair to poor condition. Each year there is a programme budget for replacement of switches, however switch replacement occurs upon receipt of unsatisfactory switch inspection results, or when poles or crossarms on which the switch is located are replaced, rather than under a structured programme of replacement based on age or location. Gas insulated load break switches are being used in strategic areas and are equipped with motor actuation for future automation. Conventional air break switches are also widely used.

The majority of the 25 overhead auto-reclosers are oil filled, with only seven being gas or vacuum insulated. The individual types of auto-reclosers are shown in the table below.

ACR Manufacturer	Insulation	ACR Model	Quantity
G&W	SF_6	RP	2
	Air / Vacuum	ViperS	5
Reyrolle	Oil	OYT	7
Metropolitan Vickers	Oil	UPC	1
Mc Graw-Edison/Kyle	Oil	KFE	6
		DAS27	2
Not recorded	N/A	N/A	2
Total			25

Figure 3-34 Summary of Auto-Recloser Types

Fault passage indicators, both remote and local, have been installed at a number of major tee offs on the overhead lines. This practice will continue to aid fault detection to allow faster restoration of areas affected by interruptions.

Manufacturer	Model	Quantity
Bardin	Flite 110	22
CHK	Not recorded	7
Not recorded	N/A	4
Total		33

Figure 3-35 Summary of Overhead Fault Passage Indicators

Age profiles of these overhead line devices are shown below.

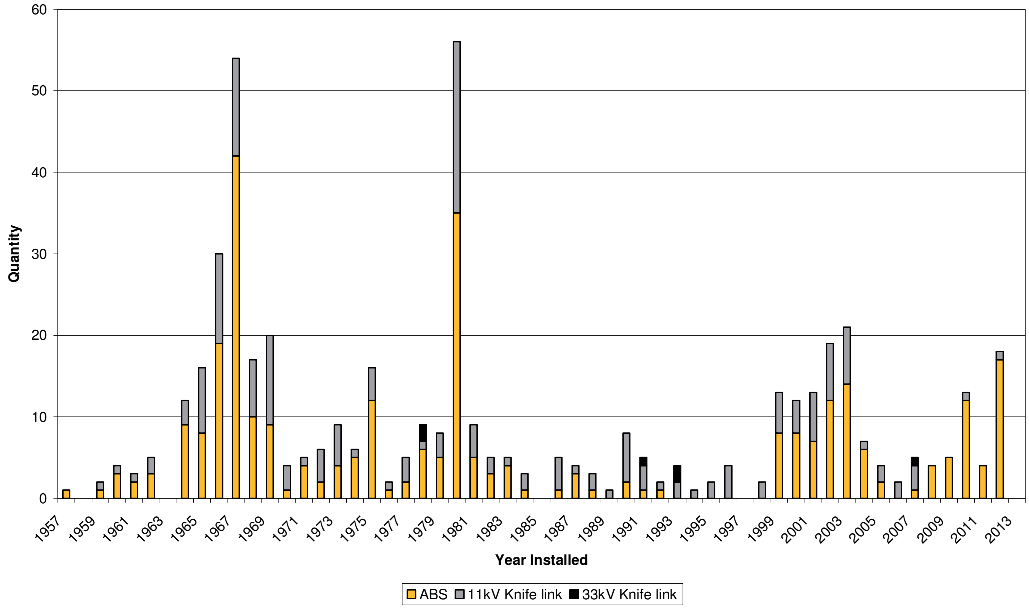


Figure 3-36 Age Profile of Overhead Switchgear and Devices

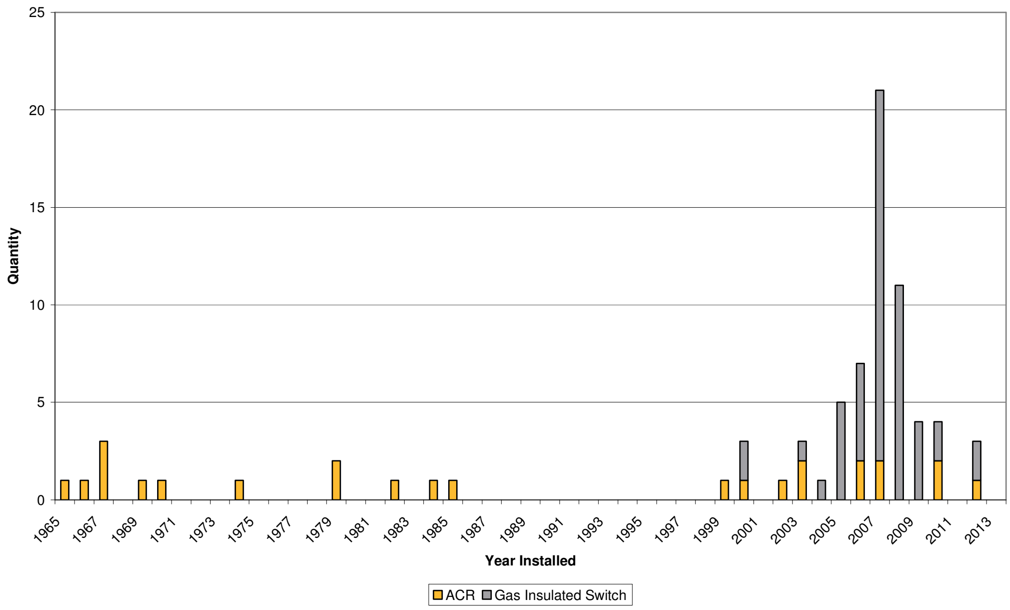


Figure 3-37 Age Profile of Overhead Auto-reclosers and Gas Switches

3.4.11. Distribution Transformers

Of the distribution transformer population, 58% is ground mounted and the remaining 42% is pole mounted. The pole mounted units are installed on single and double pole structures and are predominantly 3 phase units rated between 10 and 200kVA. The ground mounted units are 3 phase units rated between 100 and 1,500kVA. Wellington Electricity holds a variety of spare distribution transformers, in serviceable condition, to allow for quick replacement following a major defect. Other than complete units, few other spares are held for this type of asset. The design life of a distribution transformer is 45 years, although in indoor environments a longer life may be achieved. In some outdoor environments, particularly where exposed to salt spray from the sea, a transformer will not reach this age due to corrosion. The age profiles of distribution transformers are shown below.

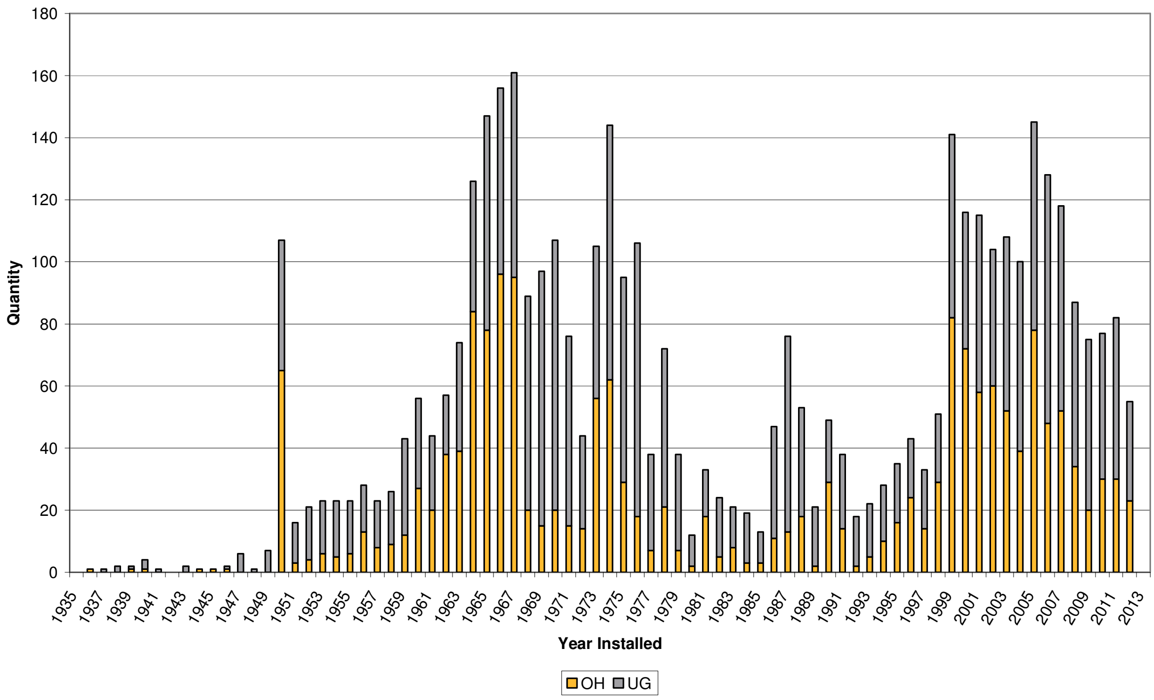


Figure 3-38 Age Profile of Distribution Transformers

In addition to pole and integral berm substations, Wellington Electricity owns 497 indoor substations and occupies a further 700 that are within customer owned accommodation (typically of masonry or block construction and occasionally wire cage construction) in the Wellington City and Hutt Valley areas. These are categorised under substation enclosures, although a large number are quite sizeable and reside on Wellington Electricity owned plots of land.

Category	Quantity
Distribution transformers	4,283

Category	Quantity
Wellington Electricity owned substations	3,526
Customer owned substation enclosures	700
Distribution substations - Total	4,226

Figure 3-39 Summary of Distribution Transformers and Substations

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

A new canopy type substation installed in a subdivision

3.4.12. Ground Mounted Distribution Switchgear

This section covers ring main units and similar switching equipment which is often mounted outdoors. It does not cover indoor circuit breakers which are widely used on the distribution network outside of zone substations as these are included under the category of Circuit Breaker. There are 1,787 ground mounted switchgear units in the Wellington Electricity network, both of the Holec Magnefix type and conventional oil insulated ring main switches such as ABB, Long and Crawford, and Statter. Most of the older switchgear is oil insulated however the newer ones use SF_6 as the main insulating medium. Magnefix has a resin casing to provide insulation. The age profile of ground mounted switchgear is shown below. In addition to these units, there are around 1,450 circuit breakers used within the distribution network, as detailed in section 3.4.5. These are not shown in the graph below.

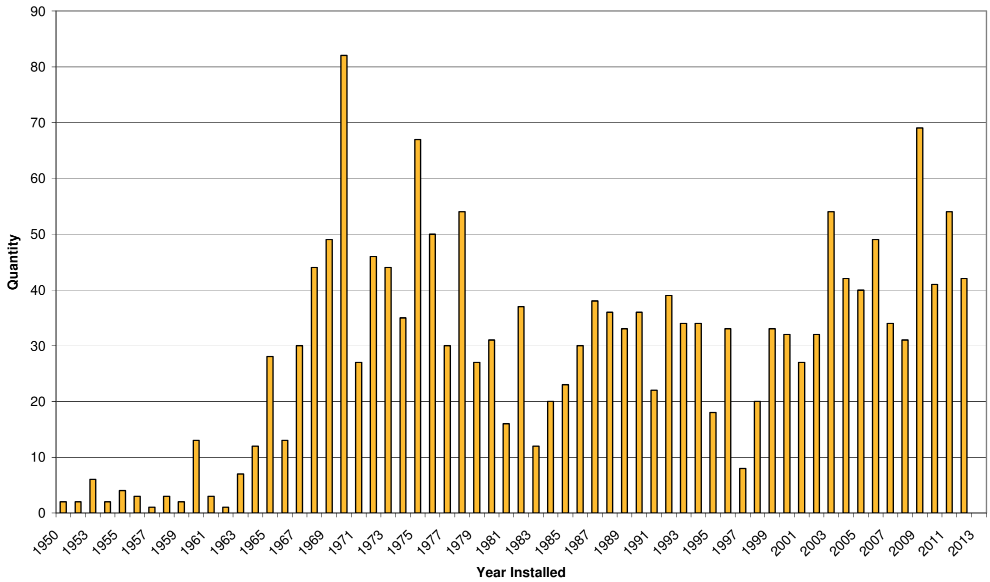


Figure 3-40 Age Profile of Ground Mounted Distribution Switchgear

The average age of the ground mounted switchgear is 25 years.

Category	Quantity
Oil Filled RMUs	282
Gas Insulated RMUs	421
Solid Insulated RMUs	1,084
Total Ring Main Units	**1,787**

Figure 3-41 Summary of Ground Mounted Distribution Switchgear

Full details of maintenance, refurbishment and renewal are covered in Section 6 (Lifecycle Asset Management).

3.4.13. HV and LV Distribution System

Wellington Electricity's network has a high percentage of underground cables, which has contributed to its high level of reliability during weather related events, although does subject it to increased risks of third party strikes during underground construction work. The 11kV underground distribution system has normally open interconnections between feeders and feeders are segmented into small switching zones using locally operated ring main switches. In the event of a cable fault the faulted cable section can be isolated and supply to downstream customers can be switched to neighbouring feeders.

Wellington CBD is operated in a closed ring configuration with radial feeders interconnecting neighbouring rings or zone substations. This part of the network uses automatically operating circuit breakers, using Solkor differential protection between sites rather than manually operated ring main switches between switching zones. This results in higher reliability as smaller sections of network are affected by cable faults. However due to the nature of the CBD, any repairs required to the distribution system take considerably longer than standard replacement times. CBD repairs also incur considerable costs for traffic management and road surface or pavement reinstatement.

In rural areas, the lines are typically radial, with limited back feeds in areas such as Akatarawa, Paekakariki Hill and Wainuiomata towards the south coast. The use of auto reclosers and sectionalisers aims to reduce the impact of a fault to a smaller section on these feeders and therefore limit the customers affected. As a result an outage is likely to affect customers for the duration of the repair.

Category	Quantity
11kV cable (incl. risers)	1,137 km
Low Voltage cable (incl. risers)	1,589 km

Figure 3-42 Summary of Distribution Cables

3.4.13.1. HV and LV Distribution Cables

Approximately 93% of the underground distribution cables are PILC and PIAS and the remaining 7% are newer XLPE insulated cables. PILC cables use a relatively old technology but are in good condition and have proven to be very reliable.

The majority of low voltage cables are PILC or PVC insulated and a much smaller number are newer XLPE insulated cables. In general the low voltage cables are in good condition.

An age profile of distribution cables of both voltages is shown below.

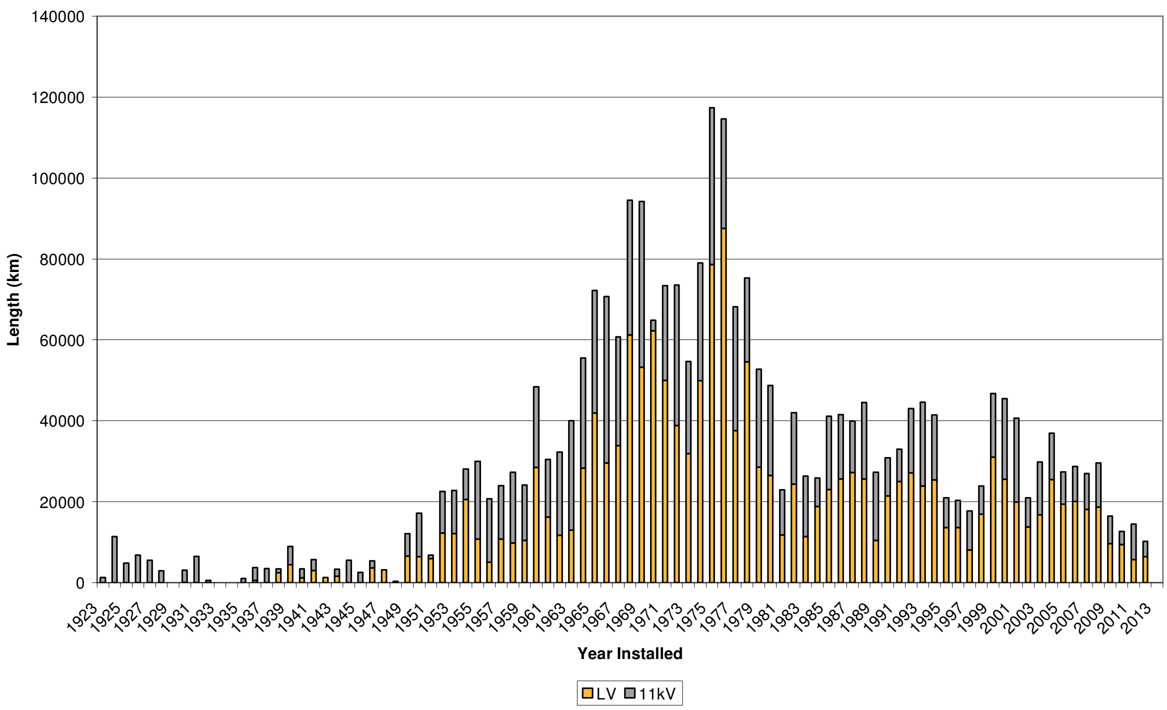


Figure 3-43 Age Profile of Distribution Cables

3.4.13.2. LV Pillars and Pits

Pillars and pits provide the point for the connection of customer service cables to the Wellington Electricity underground low voltage reticulation. They contain the fuses necessary to isolate a service cable from the network. Pits are manufactured from polyethylene as are most of the newer pillars. Earlier style pillars were constructed of concrete pipe, steel or aluminium. There are approximately 400 link pillars and pits in service on the Wellington network. These are used to parallel adjacent LV circuits to provide back feeds during outages, as well as providing the ability to sectionalise large LV circuits. A high level breakdown of types is listed below.

Type	Quantity
Customer service pillar	13,450
Customer service pit	1,322
Link pillars and pits	401
Total	15,173

Figure 3-44 Summary of LV Pillars and Pits

3.4.14. Metering

Wellington Electricity does not own any revenue metering assets as these are owned by retailers and metering companies supplying consumers.

Check meters are installed at GXPs and Maximum Demand Indicator (MDI) meters are installed in a large number of distribution substations, predominantly those used for street LV supply. These are for operational and planning purposes only and are considered to be part of that asset. In future there may be benefits obtained from accessing smart metering data from consumer premises to feed into the network planning and asset management processes, as well as real time performance of the low voltage network.

3.4.15. Generators and Mobile Substations

Wellington Electricity does not own any mobile generators or substations. There is a fixed generator supporting the disaster recovery control room site at Haywards substation. Wellington Electricity has shared use of a generator at the corporate office in Petone, however this generator is owned and maintained by others.

All generation required for network operations and outage mitigation is provided by the works contractor.

Wellington Electricity owns a canopy type substation with 11kV switchgear installed and this is used in instances where switchgear replacement or other major works is occurring at a substation and the 11kV supply cannot be out of service for extended periods. This equipment is stored at the Bouverie Street yard and is deployed for planned work to assist with supply continuity and security. It can also be used for fault restoration or where catastrophic damage has occurred to an 11kV switchboard however it has not been used for this purpose to date. This equipment is inspected and maintained when it is used, and at other times by the Field Service Provider under the management of critical and emergency spares policies.

In the future Wellington Electricity proposes to evaluate where in the network private backup generation is installed that can be synchronised, particularly large generators in the CBD, and how this can be utilised for maintaining customer supply or assisting during network outages or Grid Emergencies. This will require the engagement of both retailers and the consumers with the generators, and an understanding of connection arrangements and generator capabilities, as well as customer willingness to participate in such an arrangement. Developments in this area are being made by load aggregators and other third parties, which may require further co-ordination with these parties to realise the benefits that may be obtained by Wellington Electricity and consumers in this space.

3.4.16. Assets Located at Bulk Electricity Supply Points Owned by Others

Wellington Electricity owns a range of equipment installed at bulk electricity supply points owned by others (Transpower GXPs). These assets are included in the asset categories listed above, but are described further below.

3.4.16.1. 33kV and 11kV lines, poles and cables

Wellington Electricity owns lines, poles, cables, and cable support structures at all GXPs from which it takes supply. The Wellington City area is fully cabled, whereas in the Hutt Valley area many circuits leave via an overhead line.

3.4.16.2. 11kV switchgear

Wellington Electricity owns the 11kV switchgear located within the Kaiwharawhara GXP which is used as a Point of Supply.

3.4.16.3. Protection Relays and Metering

Wellington Electricity owns 33kV line and cable protection (differential) and inter-tripping relays at all GXPs except Kaiwharawhara. At Kaiwharawhara, Wellington Electricity owns the relays associated with the 11kV switchgear except those on the incomers which are owned by Transpower. Wellington Electricity also owns check metering at all GXPs.

3.4.16.4. SCADA, RTUs and Communications equipment

Wellington Electricity owns SCADA RTUs and associated communications equipment at all GXPs.

3.4.16.5. DC power supplies and battery banks

Wellington Electricity owns battery banks and DC supply equipment at all GXPs.

3.4.16.6. Load Control Equipment

Wellington Electricity owns load control injection plant at Haywards and Melling GXPs, and also has ripple blocking circuits installed on the 33kV bus at Takapu Road, Melling and Upper Hutt GXPs.

3.4.17. Non Network Assets

In addition to the network assets described in the sections above, Wellington Electricity also owns a range of non-network assets which are not used for the conveyance of electricity but support the business.

3.4.17.1. Information Technology Assets

Wellington Electricity owns a range of desktop and laptop computers, servers and networking equipment related to the corporate IT network. These are too numerous to detail individually.

Software and user licenses for a range of packages including Smallworld GIS, SCADA, Powerfactory, Projectwise, Microstation CAD and SAP are also owned by Wellington Electricity.

Wellington Electricity owns a range of landline and cellular telephones for the corporate office and for staff use. For major event and disaster recovery, a number of Iridium Satellite phones are also owned.

3.4.17.2. Building Improvements and Furniture

The building improvements, signage and major plant installed by Wellington Electricity including air conditioning upgrades are considered to be a non network asset. Wellington Electricity does not own the buildings at either the Petone corporate office or the Haywards disaster recovery control room however lease arrangements are managed with appropriate rights of renewal available.

Wellington Electricity owns furniture in the Petone corporate office and the Haywards disaster recovery control room including desks, chairs, shelving, kitchen related equipment and artwork.

3.4.17.3. Plant and Machinery

Wellington Electricity owns very little in the way of plant and machinery due to the outsourced field service model. There are six motor vehicles which are operated under a finance lease and used by the business. There are no personal use vehicles utilised by the business.

Wellington Electricity owns a small range of tools such as test sets relating to the Deuar pole testing system and an UltraTEV+ unit which is used by both Wellington Electricity and also loaned to Field Service Providers to undertake specific diagnostic testing. Where possible Field Service Providers are encouraged to purchase and hold specialist test equipment. Tools and equipment owned by Wellington Electricity is tested and calibrated in accordance with the manufacturer's recommendations to ensure reliable and accurate operation.

3.4.17.4. Land and other buildings

The land purchased at Grenada in 2012 for the future development of the Grenada zone substation is currently classified as a non network asset. This is due to the Commerce Commission rules preventing this being added to the network Regulatory Asset Base (asset RAB) until such time as it is used for electricity purposes. Wellington Electricity also owns an undeveloped site at Bond Street in the Wellington CBD which is intended for future substation use. There are three residential properties located on the same parcel of land that the Karori zone substation is built upon. These houses are rented out at market rents.

3.5. Asset Justification

The distribution system is designed to provide a safe electricity supply of sufficient capacity and reliability to meet the quality of supply and customer service levels for the load type that is acceptable when giving consideration of the price/quality trade-off consumer groups are prepared to make. In addition, the network is planned and constructed with some additional capacity or ability to shift controllable load from peak congestion periods into areas or lower usage to cater for forecast load increases. This strategy (which is adopted by electricity network businesses) is an efficient approach to network development due to the high cost and long life cycles of electricity distribution infrastructure assets.

Urban Network

The urban network, both in residential and business/CBD areas, is designed to support present and recently forecast loads, and to be operated within the disclosed service levels for the period of this AMP. Where shortfalls are identified, network reinforcement projects or demand side initiatives (or a mixture of both) may be undertaken. There are different network architectures between the former Capital MED (Wellington City Council) and Hutt Valley areas, and as such there is a higher level of security in the Wellington CBD, and surrounding suburbs, which incorporates an increased number of circuit breakers and protection devices, a predominantly underground network due to the building density, as well as offering a higher level of redundancy. This legacy system architecture is appropriate to meet the security criteria for the CBD and also reflects the significance of the Wellington CBD as being the centre of Government, Government departments and commerce and their reliance upon secure electricity supply. Following recent seismic events in Canterbury, resilience of supply is also being considered in network planning. Supply is taken at 33kV to supply zone substations from Transpower GXPs. This is an industry standard voltage and is appropriate to minimise losses as well as carry the required loads. Distribution feeders are all 11kV, which is stepped down at distribution substations to 400V for distribution to consumer premises. In some areas, supply is taken from Transpower at 11kV where the load centre is close to the GXP. There has been reasonably low load growth in the Wellington network over recent years and the decline of manufacturing industry from the 1980s onwards has created headroom in some areas of the network, especially the Hutt Valley and Porirua areas. Despite this, changing load demands (apartment conversions, new buildings and building conversions, increased use of air conditioning etc) in the CBD has created some constraints that will require further network development.

Rural Network

The rural network is supplied at 11kV from urban zone substations and often a rural feeder passes through an urban area supplying load before entering a rural area. There are fewer back feed options for rural feeders and this is reflected in lower service levels. Less than 30% of the Wellington network (by length) is rural and the load served is very low density. There is no major rural sector in the Wellington area so loading and voltage is not an issue compared with other rural network areas experiencing high loads due to irrigation and intensive agricultural activities. However, the exposure to weather and vegetation interference necessitates a large number of line reclosers, remote switches and sectionalisers to meet service level targets.

Voltage Levels

11kV has been the predominant distribution voltage as this was the original supply voltage from the first grid connected substation at Khandallah established in 1924 to supply Wellington and the subsequent development and connection of Melling and Central Park substations in the 1930s and 1940s.

33kV was introduced in the late 1950s for subtransmission when load growth exceeded the capacity of the 11kV system. Wellington Electricity has no intention in the short term to use other voltages for distribution or subtransmission.

110kV cabling was installed by the Wellington MED in the early 1980s to future proof supply capacity to the Eastern Suburbs area (incorporating Evan's Bay and Miramar), although this is presently operated at 33kV. Wellington Electricity is considering the use of 110kV in this area in the future, as described in Section 5 (Network Planning).

4. Service Levels

4.1. Consumer Orientated Performance Targets

4.1.1. Network Reliability

Network reliability is measured using two internationally recognised performance indicators, SAIDI and SAIFI, which taken together are indicators of the availability of an electricity supply to the average customer connected to the network.

- SAIDI[4] is a measure of the total time in a measurement year that an electricity supply is not available to the average consumer connected to the network. It is measured in minutes.
- SAIFI[5] is a measure of the total number of supply interruptions that the average consumer experiences in the measurement period. It is measured in number of interruptions[6].

These indicators include both planned and unplanned outages. On average, planned outages account for approximately 10% of the total number of outages every year but only contribute to 3% of the annual SAIDI minutes. Consistent with the approach taken by the Commerce Commission the following supply interruptions are not included in the measured performance indicators.

- Interruptions caused by the unavailability of supply at a GXP, or as a result of automatic or manual load shedding directed by the transmission grid operator[7], or as a result of some other event external to the Wellington Electricity network.
- Interruptions lasting less than one minute. In these cases restoration is usually automatic and the interruption will not be recorded for performance measure purposes, however, it is recorded in Wellington Electricity's systems for future analysis.
- Interruptions resulting from an outage of the low voltage network or a single phase outage of the 11kV distribution network. The Commerce Commission does not require these interruptions to be recorded for information disclosure or for the operation of the price-quality control regime. In practice such interruptions do not have a material impact on measured system reliability and the business processes required to accurately record these interruptions and measure their impact are not cost effective.

Wellington Electricity has calculated reliability limits using the methodology set down by the Commerce Commission[8]. This method adopts a reference set of reliability data taken from the period 1 April 2004 to 31 March 2009. The mean reliability over this period is set as the target for the network and the mean plus one standard deviation become the limit. This method is applied to both SAIDI and SAIFI. The mean and limit values for Wellington Electricity calculated using this method are presented below.

Justification for the targets Wellington Electricity has set is explained in section 4.3.

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[4] System Average Interruption Duration Index

[5] System Average Interruption Frequency Index

[6] Due to the effect of averaging, SAIFI is reported as a non integer number.

[7] The transmission grid operator has the authority to direct electricity distributors to shed load. This is necessary during emergencies to ensure that the power system continues to operate in a secure and stable state.

[8] Commerce Commission, Electricity Distribution Services Default Price-Quality Path Determination 2012, Schedule 2.

	2010-11	2011-12	2012-13	2013-14	2014-15	2015-23
SAIDI target (mean)	**33.90**	**33.90**	**33.90**	**33.90**	**33.90**	**33.90**
SAIDI limit (mean + 1SD)	40.74	40.74	40.74	40.74	40.74	40.74
SAIFI target (mean)	**0.52**	**0.52**	**0.52**	**0.52**	**0.52**	**0.52**
SAIFI limit (mean + 1SD)	0.60	0.60	0.60	0.60	0.60	0.60

Figure 4-1 Reliability Targets and Limits (as defined by the Regulator)

Note 1: SAIDI is measured in minutes and SAIFI in average number of interruptions.

Note 2: Targets for the period 2015-2023 are based upon the present methodology and may differ from 2015 onwards.

The limits have been calculated in accordance with the Commerce Commission's current requirements for the reporting of reliability and include the impact of major event days when the number of outages exceeded the ability of Wellington Electricity's contractor to respond in a timely manner.

Major event days are usually caused by environmental factors, such as severe storms, that are outside Wellington Electricity's direct control. They are relatively infrequent – Wellington Electricity has experienced only three major event days in the last eight years, two in 2003-04 and one in 2004-05. They generally have a much bigger impact on SAIDI than on SAIFI because during such events consumers may only experience one interruption but can be without power for hours or, in extreme situations, days.

The measured historic reliability of Wellington Electricity's network is illustrated in the graphs below. In broad terms the graphs show that, under normal circumstances, the average consumer can expect one sustained interruption every two years and that this interruption will last a little over an hour.

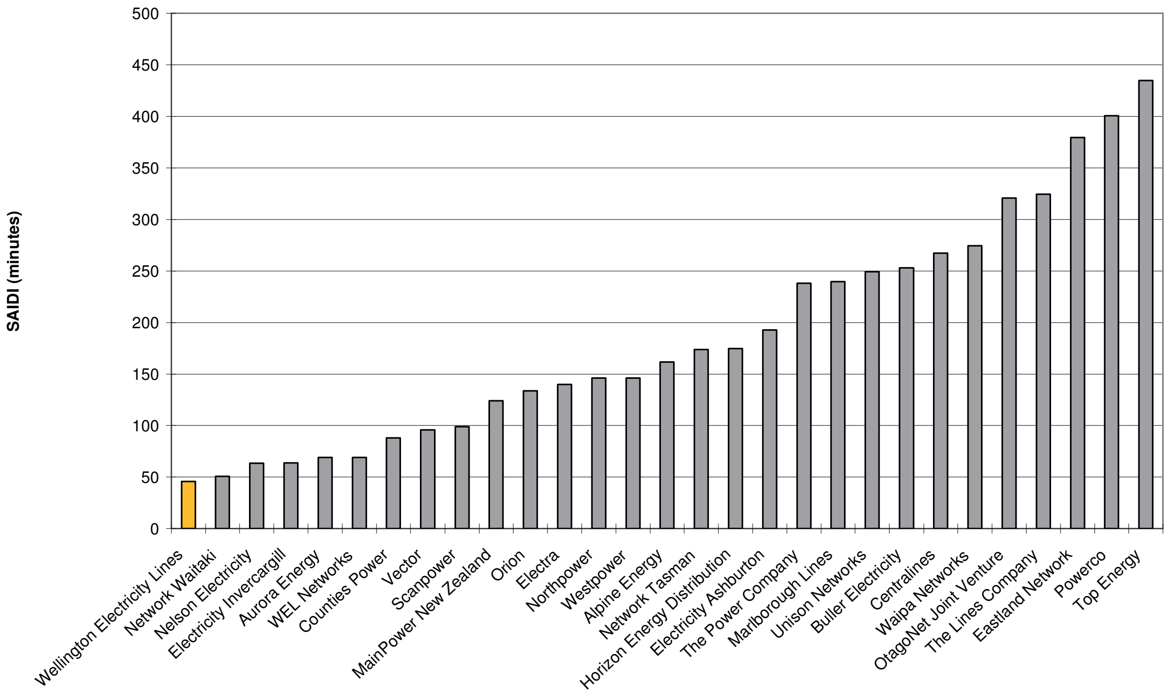

Figure 4-2 NZ Electricity Distribution Network performance 2011/12

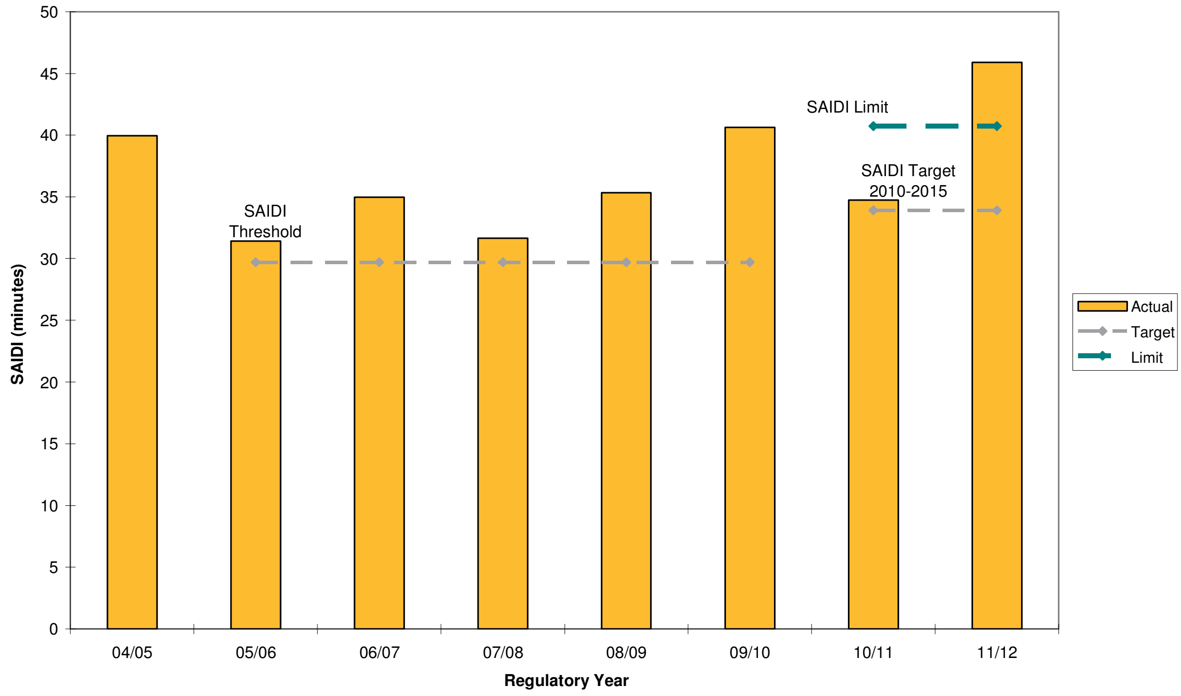

Figure 4-3 Historic SAIDI of the Wellington Electricity Network

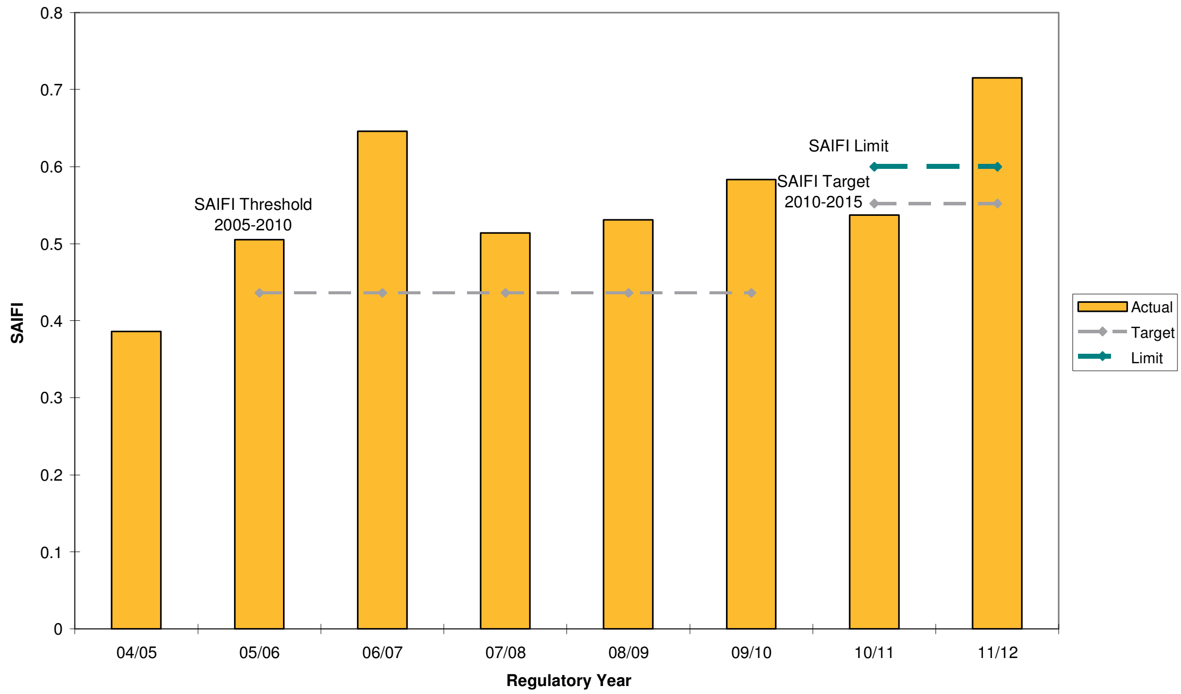

Figure 4-4 Historic SAIFI of the Wellington Electricity Network

4.1.2. Contact Centre Service Levels

Wellington Electricity has developed a set of key performance indicators and financial incentives that will serve as service level benchmarks with its contact centre provider (Telnet) and these are set out below. Measurement is by way of the Telnet monthly online Executive Summary Report.

4.1.2.1. General Contact Centre Service Levels

SL	Service Element	Measure	KPI	2012 Actual	2013 Target	2014-2023
A1	Overall service Level	Average service level across all categories	80%	95.9%	82.5%	85.0%
A2	Call response	Average wait time across all categories	20 seconds	17 seconds	18 seconds	18 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	4%	2.3%	3.50%	3%

Figure 4-5 General Contact Centre Service Level Benchmarks

Overall Service Level (A1) - This is the measure of calls answered within 20 seconds. The target is 80% of calls answered within 20 seconds. This target is an international standard for utility call centres.

Call response (A2) - This is a measure of the average call response (waiting) time. The target is 20 seconds average wait. This target is an international standard for utility call centres and is continually being updated within the call centre industry by customer survey results.

Missed calls (A3) - This is a measure of abandoned calls, where the caller hangs up prior to the call being answered. The target is 4% of calls, or fewer. This target is an international standard for utility call centres which recognises that calls may be abandoned for a variety of reasons, including some not related to the call centre. However an abandonment rate above 4% may be indicative of an issue with the call centre service.

4.1.2.2. Customer Experience

All customer contact should contribute to customer satisfaction in dealings with the service provider when representing Wellington Electricity. Measurement is by way of a random sample survey of callers with the sample selected by Wellington Electricity.

SL	Service Element	Measure	KPI	2012 Actual	2013 Target	2014-2023
C1	Specific Contact Centre experience	Wellington Electricity is properly represented during specific calls	Qualitative assessment 80%	88.6%	82.5%	82.5%

Figure 4-6 Customer Experience

Note C1: Contact Centre contribution to customer experience will be monitored as part of Wellington Electricity's monthly survey of Contact Centre calls. The relevant results of this survey will be discussed with Telnet with a view to constant performance improvement.

Specific Contact Centre experience (C1) - This is reported as "sample of 10 calls from on-line reporting" of the quality of interaction with callers. The target is to reach a minimum of 80% and was developed to focus on contact elements that are particularly important to Wellington Electricity. The contact elements primarily relate to the efficient management of fault and emergency calls, effective interaction with energy retailers and representing Wellington Electricity in a responsive and professional manner with the general public.

4.1.2.3. Energy Retailer Satisfaction

All energy retailer contact should contribute to energy retailer satisfaction in dealings with the service provider when representing Wellington Electricity. Measurement is by way of an annual survey.

SL	Service Element	Measure	KPI	2012 Actual	2013 Target	2014-2023
D1	Overall retailer satisfaction with Contact Centre performance	Wellington Electricity is properly represented with retailer interaction	80% satisfied	94%	82.5%	82.5%

Figure 4-7 Energy Retailer Satisfaction

4.1.3. Customer Enquiries and Complaints

Enquiries and complaints are channelled to Wellington Electricity via a number of avenues including retailers, service contractors, contact centres and direct approaches. When an enquiry or complaint is received, it is entered into a central registry (SAP–CARE database). The target response time for enquiries is eight working days and for complaints is 10 working days. Failure to meet these targets will result in automatic prompting for seven days followed by internal escalation. Wellington Electricity is a member of the Electricity and Gas Complaints Commission (EGCC) and follows their process for dispute resolution. Recent changes proposed under the EA Model Use of System Agreement will lead to Wellington Electricity (and all Electricity Lines Businesses) having to indemnify retailers under the Consumer Guarantees Act 1993 for goods and services performance related to distribution network outages. This is expected to increase the number of enquiries and complaints received by Lines Businesses.

4.2. Asset Management Performance Targets

Other performance targets used by Wellington Electricity relate to the efficiency with which Wellington Electricity manages its fixed distribution assets. The indicators for these performance targets have been selected on the basis that Wellington Electricity considers them particularly relevant to the operation and management of its assets. The indicators are also required for reporting to the Commerce Commission under its information disclosure regime.

4.2.1. Standard Service Levels for Restoration of Power

Wellington Electricity's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to three different categories of customers, as shown in the map below. These service levels are agreed between Wellington Electricity and all retailers and provides Wellington Electricity with financial incentives to not exceed the maximum restoration times detailed below. These standard service levels apply for the entire AMP period (2013 to 2023), however they are subject to change following negotiation of Wellington Electricity's revised Use of System agreement. This agreement has been developed on the basis of the Electricity Authority's Model Use of System Agreement, however this new agreement is not yet in place.

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Figure 4-8 Standard Service Levels for Residential Customers

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Figure 4-9 Standard Service Levels for Business Customers

	CBD / Industrial	Urban	Rural
Maximum time to restore power	3 hours	3 hours	6 hours

Figure 4-10 Standard Service Levels for Industrial Customers

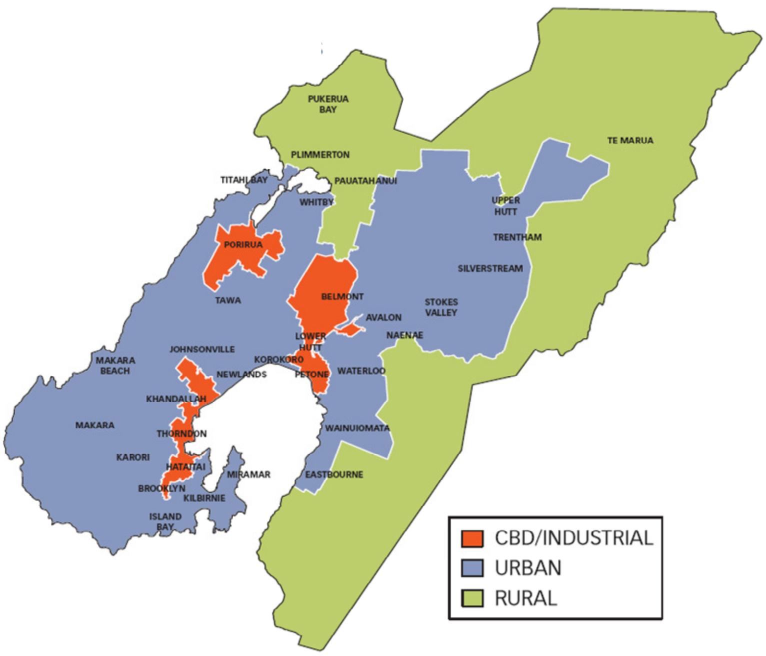

Figure 4-11 Standard Service Level Areas

Time taken to restore power is recorded in ENMAC. Refer to Section 2 (Background and Objectives) for details on how unplanned outages are recorded.

4.2.2. Faults per 100 Circuit-km

For the purpose of this performance indicator (faults per 100 Circuit-km), a fault is considered an unplanned failure of an in-service line or cable asset on the subtransmission or high voltage distribution systems, irrespective of whether or not it causes a loss of supply to customers. Circuit-km relates to the total circuit length of the subtransmission and high voltage distribution systems, irrespective of whether the circuit is overhead or underground. This indicator is a measure of how well the system is designed and operated from a technical perspective.

Wellington Electricity designs its network to withstand the environmental conditions to which it is exposed, particularly the severe Wellington winds and the high level of atmospheric salt contamination. As discussed in section 6, Wellington Electricity has a preventive maintenance system in place whereby assets are regularly inspected to identify and remedy defects that could potentially cause an asset failure. In addition Wellington Electricity has a vegetation management system in place to reduce the number of faults resulting from trees coming into contact with overhead power lines. Faults are also subject to a root cause analysis aimed at identifying systemic issues that may be causing unplanned outages followed by projects that will address the issue. This performance indicator (faults per 100 Circuit-km) is a measure of the effectiveness of these asset management strategies.

The table below sets out the performance indicator targets for the planning period. The current target has been set based on the current performance of the network and considering performance over the previous four regulatory years since the purchase of the network. The intended targets reflect a continuation of the current level of asset performance. Faults per 100 circuit kilometre in 2011/12 was higher than target as a high number of storm event faults and an increase in third party strikes affected it, compared with previous years.

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
Target	11.6	11.7	11.9	12.0	12.2	12.3	12.5	12.6	12.8	12.9	13.1	13.2	13.3	13.5	13.6
Actual	7.1	12.6	11.9	13.3											

Figure 4-12 Performance Targets for Faults per 100 Circuit-km

4.2.3. Asset Efficiency and Utilisation

Load factor is reflective of consumer demand profiles and the predominantly urban network leads to higher than average utilisation and load density. Wellington Electricity aims to maintain utilisation and loss ratios at steady levels in line with similar networks. Where assets are being replaced, consideration is given to reducing losses through selection of more efficient equipment, generally in the selection of transformers. The following table provides an overview of the efficiency of the assets utilised by Wellington Electricity compared with the industry average.

	Load factor %	Distribution transformer capacity utilisation %	Loss ratio %	Demand density kW/km	Volume density MWh/km	Connection point density ICP/km	Energy density kWh/ICP
Industry average 2010-11	59.6	31.3	5.5	39.0	199	13	15231
Wellington Electricity 2010-11	51.7	42.6	4.8	124.0	533	36	14946
Wellington Electricity 2011-12	48.0	45.7	4.8	133.0	531	36	14935

Figure 4-13 Asset Efficiency and Utilisation

4.3. Justification for Targets

Wellington Electricity operates its distribution system in accordance with all relevant legal requirements, including the Electricity Act 1992 and associated regulations, the Health and Safety in Employment Act 1992, and the Resource Management Act 1991, the Electricity Industry Act 2010 and the Commerce Act 1986 and all regulations associated with theses Acts.. This legislation and subsidiary regulations have a significant influence on the way Wellington Electricity manages its assets. For the most part the legal requirements are non-discretionary and therefore act as a constraint on the way in which the system must be managed (with associated costs in managing the network under these constraints).

Within these legal constraints, Wellington Electricity must still meet the requirements of its stakeholders. It must ensure that safety is not compromised and the quality and reliability of supply meet the expectations of retailers and consumers at a price level which reflects the service level they require.

4.3.1. Consumer Survey

Wellington Electricity conducts a major phone survey of its consumers to determine their expectations on a periodic basis (at least once every two years). The purpose of these surveys is to establish consumer views on how well Wellington Electricity is meeting the expectations of consumers.

The most recent survey was completed in December 2011 and involved surveying:

- The top 25 consumers (industrial consumers)
- A random sample of 25 of the top 26 to 130 consumers (industrial and business consumers)
- A random sample of 3,500 residential consumers

Of the 3,500 residential consumers called, a total of 412 completed the survey - a response rate of 13%. The survey questions included:

- What is most important (service issue) to consumers? (e.g. keeping power on, low prices etc)
- How well is Wellington Electricity performing?
- What price / quality tradeoffs are consumers prepared to make? (e.g. pay less for lower quality etc)

Graphs of the responses to these questions are provided below.

Wellington Electricity will survey consumers again during 2013. The results of that survey will be included in the 2014 Asset Management Plan and used to assist with the setting of performance targets.

In addition to this major survey, interim surveys are conducted following service calls to the Contact Centre to establish customer views on how well Wellington Electricity and our service providers meet service levels for the specific service call that was raised.

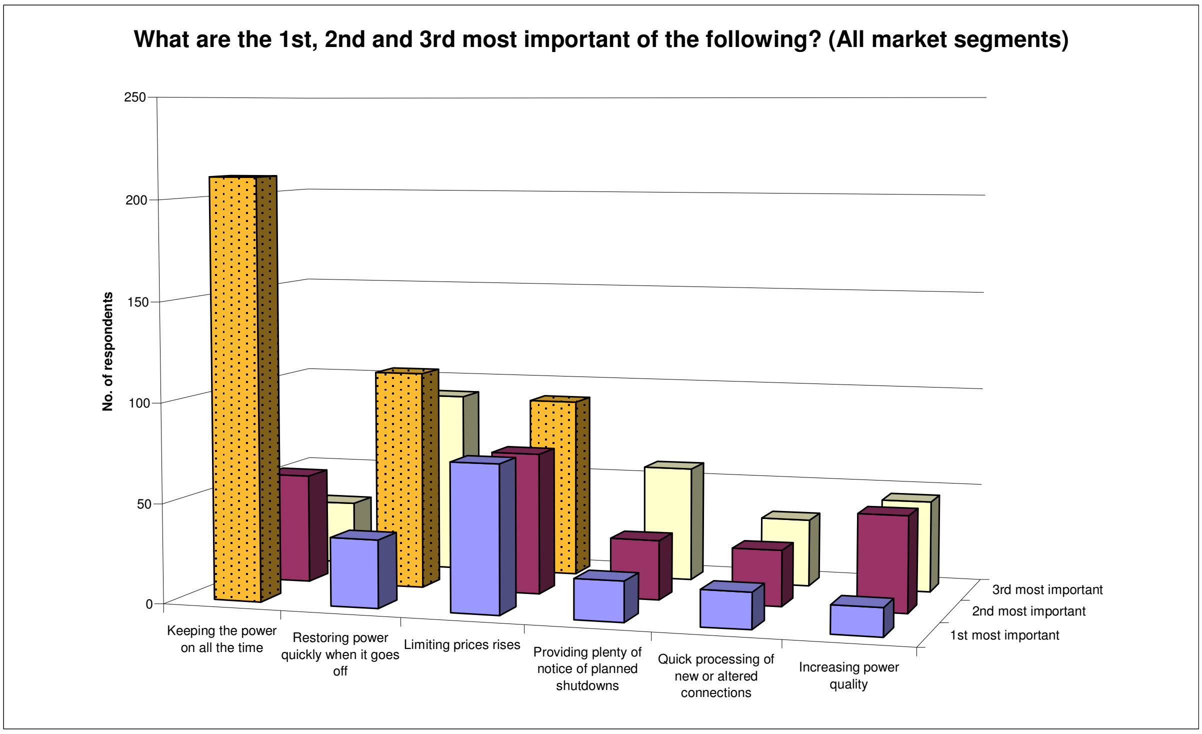

Figure 4-14 What is most important to consumers?

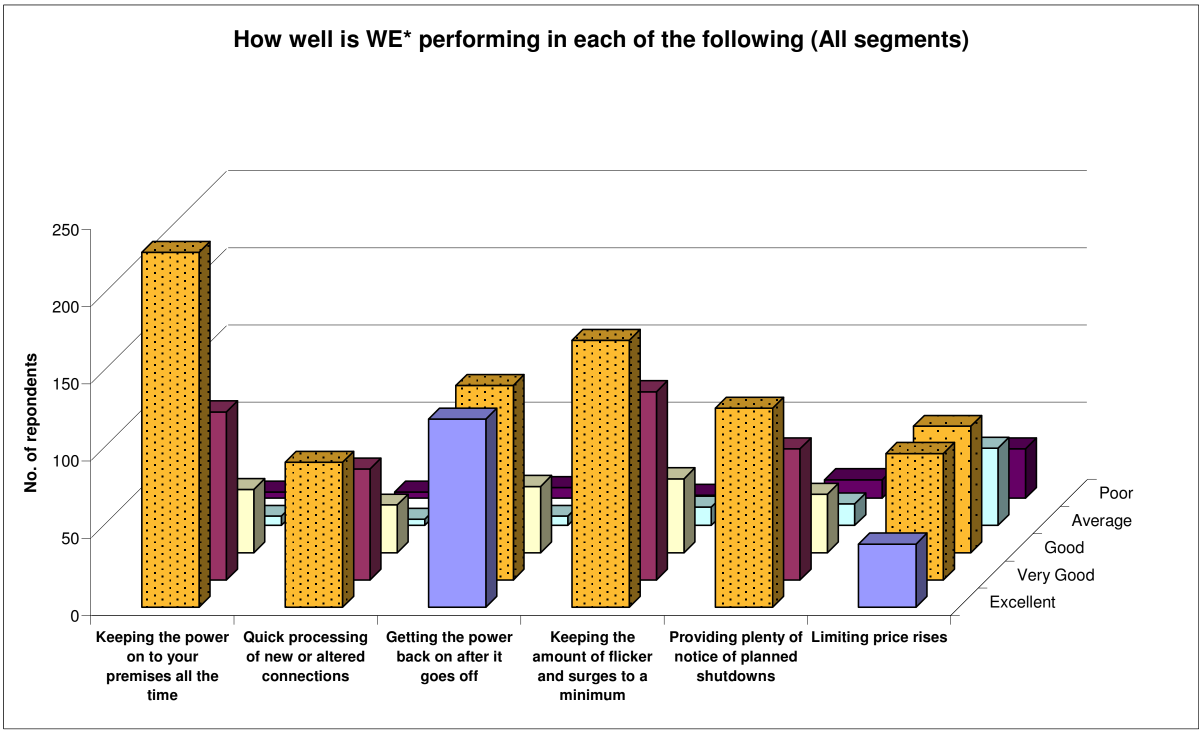

Figure 4-15 How well is Wellington Electricity performing?

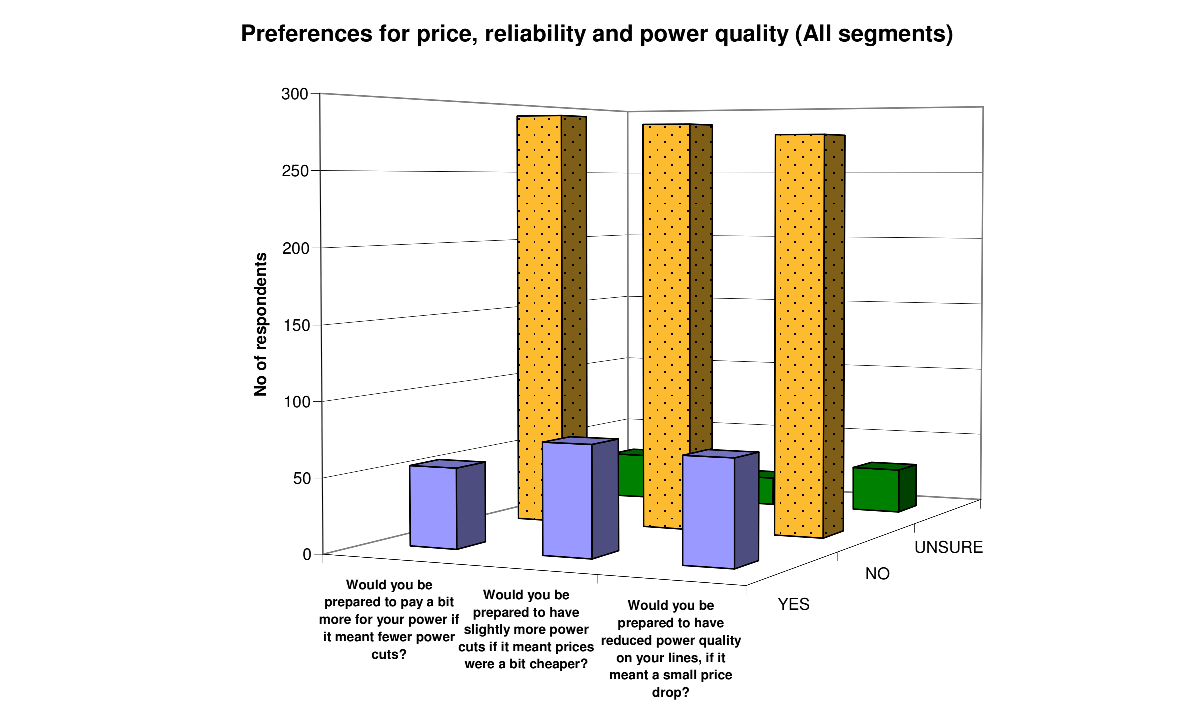

Figure 4-16 What price / quality tradeoffs are consumers prepared to make?

Key results from the 2011 survey are:

- Consumers in all segments regard continuity ('keeping the power on') and restoration ('getting the power back on') as the first and second most important components of electricity line services
- Consumers across all segments regard Wellington Electricity's performance in regard to the above two components as either excellent or very good
- Limiting price increases is the third most important component
- The majority of consumers across all segments indicated a clear preference against paying either a bit less if it meant more power cuts or a bit more if it meant less power cuts. This indicates a strong preference for paying about the same line charges to have about the same reliability
- The majority of consumers across all segments indicated a clear preference against paying a bit less to have more flicker or surge. This indicates a strong preference for having either the same or less flicker

The survey shows that consumers are advising Wellington Electricity that:

- Efforts and resources should be focused on continuity and restoration
- Price increases matter less than maintaining the status quo on quality
- Present levels of quality are about right

These results are reflected in Wellington Electricity's asset management approach of investing to maintain reliability at present levels. As a result, the following objectives have been set:

- To maintain service continuity and restoration of electricity supply as priorities
- To improve the response time of service providers to customer calls
- To maintain the quality of electricity supply being delivered
- To provide sufficient notice for any planned shutdowns

5. Network Planning

5.1. Planning Criteria and Assumptions

Network development planning is concerned with delivering network performance and security of supply:

- In an economic, sustainable and profitable manner
- At a price level which is acceptable for the quality expected by customers
- Maintaining risk at a level which is acceptable to the Wellington Electricity Board.

The principles which underpin network planning are encapsulated in a number of standards, with the key document being the Wellington Electricity security standard. The main planning principles are:

- Network assets will not present a safety risk to staff, contractors or the public
- All network assets will be operated within their design rating
- The network is designed to meet statutory requirements including acceptable voltage and Power Quality (PQ) levels
- Customer's[9] reasonable electricity capacity requirements will be met
- 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
- Varying security standards apply to different network areas (CBD/industrial, urban, rural) and customer segments, broadly reflecting customers' price/quality trade-off
- Network investment will provide an appropriate commercial return for the business

These principles create competing priorities which must be balanced to find the best outcomes for Wellington Electricity and its stakeholders. Following on from the Canterbury earthquakes, resilience considerations may need to be included in this list. This is further discussed in Section 8 – Risk Management.

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

- Network security – 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 (i.e. capital cost, asset ratings, maintenance costs and expected life are optimised to achieve overall lowest cost). Standardisation also reduces design costs and minimises spare equipment holding costs leading to lower overall project costs
- Network parameters – including acceptable fault levels, voltage levels, power factor, etc., providing an appropriate operating framework for the network.

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

To identify the network constraints within the planning period, the forecast peak load for future years contained within the moderate load forecast is compared with the capacity of the network equipment to produce a list of overloaded assets. This is done for both system normal (n) and contingency (n-1) conditions. Solutions to resolve asset overloads at times of forecast peak load are considered for inclusion in the capital budget submission if the relevant network planning criteria for the asset are violated.

Wellington Electricity plans to eliminate the constraints by implementing optimum solutions to the network which has been forecasted to be overloaded during normal conditions. In some cases the solution for contingency events for some components of the network may be delayed depending on response times, repair times and the consequences of the overload.

Typical repair time assumptions for main power system equipment are:

- Substation transformer - 5 days
- 33kV Underground cable - 9 days
- 33kV Circuit breaker - 3 days
- 33kV Overhead line - 10 hours

When the forecast load exceeds the security criteria, a constraint is defined and a suitable solution is sought. Projects required to avoid breaching the load thresholds established within the planning criteria are submitted for each year's capital budget and the 10 year capital plan where:

- The overload cannot be eliminated by load transfers for distribution substations and distribution feeders
- Normal load is greater than a distribution substations normal capacity (a tolerance of 0.2 MVA is considered to allow for metering errors)
- Load during a contingency event is greater than a distribution substation's firm delivery capacity
- During a contingency event, the load at risk on the feeder is greater than 100A (i.e. approx 2MVA at 11kV)
- Normal load is greater than a sub transmission line's normal rating or the contingency load is greater than a sub-transmission line's emergency rating.

5.2. Prioritisation of Capital Works Projects

The processes described in this AMP invariably identify more potential work than can be accommodated by budgets or resources available to Wellington Electricity, hence the need for a project prioritisation process.

Every year, as part of the capital works budgeting process, the list of potential projects is reviewed for necessity and prioritised accordingly. The detail of how projects are prioritised has been developed further through 2012 and will form an assessment tool for projects in selection within the 2013 programme and in future years. The drivers which assist with prioritisation of projects are:

- Health and Safety
- Legal and statutory obligations
- Company policies and standards
- Risk to the network
- Environmental
- Financial value
- Quality of supply

- Strategic benefit
- Stakeholder satisfaction

A subset of the projects are non-discretionary and will be outside of the prioritisation process and will not be deferred. These projects include:

- Works necessary to ensure public and employee safety
- Works necessary to meet legal requirements.

5.2.1. Cost and Risk Factors

Where changes to legal requirements impose significant additional costs it may be necessary to undertake the required works over an extended period of time. This is usually agreed with the authority responsible for monitoring compliance with the changed requirement. Under a Default Price Path there are limitations to what can be achieved and the step change to gain a Customised Price Path presents a significant investment in time and cost with no guarantee of success.

All other projects will be prioritised on the basis of benefit-cost ratios and risk analysis using an assessment of the project 'drivers' as outlined above. Projects that mitigate extreme or high risks to the business and projects with high benefit-cost ratios will be generally given the highest priority.

An example of the prioritisation criteria is shown in the risk example in Section 8 (Risk Management).

5.2.2. Prioritisation Process

Wellington Electricity's general prioritisation sequence for including projects in its capital expenditure programme is as follows:

- Essential safety or legal compliance
- Customer initiated projects
- Network integrity projects for meeting capacity requirements
- Reliability and security of supply projects
- Other economically attractive investments.

Wellington Electricity's top priority is to operate a safe and reliable network, and it prioritises those projects which provide safety and reliability benefits above others. However all projects must provide an appropriate return to shareholders either financially, in the case of asset replacement, network growth and reinforcement projects, or through non-financial benefits such as safety, compliance or to meet regulatory requirements.

Customer driven growth projects generally result from the development of new subdivisions, commercial or industrial projects. Where possible, these projects are prioritised to meet customer's needs. These customer priorities (where Wellington Electricity has been advised in advance) are incorporated into Wellington Electricity's project execution schedules. Related to customer driven projects are those that are implemented to ensure that Wellington Electricity can meet the load capacity requirements on all parts of its network. In general no shortfalls in supply capacity would be tolerated. Network integrity projects are those that address the continued effective operation of the distribution network and include renewal and refurbishment projects.

Reliability and security of supply projects are focused on ensuring that the required reliability standards on the network are met and that security of supply standards are maintained.

Projects are prioritised in accordance with the level of the risk that they are intended to address while the outcome of the planning process identifies actual and potential network security breaches. Security breaches are assessed in accordance with Wellington Electricity's risk matrix which considers the likely frequency and consequences of the breach[10]. The higher the risk assessment factor, the higher the priority attached to a project.

5.3. Voltage Levels

Sub-transmission voltage is nominally 33kV in line with the source voltage at the supplying GXP. The voltage used at MV distribution level is nominally 11kV. The LV distribution network supplies the majority of customers at nominally 230V single phase or 400V three phase. By agreement with customers, supply can also be connected at 11kV or 33kV depending upon their load requirements.

Regulation 28 of the Electricity (Safety) Regulations 2010 requires that standard LV supply voltages (230V single phase or 400V three phase) must be kept within +/-6% of the nominal supply voltage calculated at the point of supply, except for momentary 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. All Wellington Electricity zone transformers are fitted with on-load tap changers (OLTC) to maintain the supply voltage within acceptable limits. Distribution transformers typically have an off-load tap changer which can be manually adjusted to maintain acceptable voltage in localised areas of low voltage distribution.

5.4. Security Criteria and Assumptions

The security criteria on which the design of the system is based is shown in Figures 5-1 and 5-2. This security criteria was adopted from the previous network owners and was the basis on which the network was designed and operated. There are no regulated national standards currently in force, however the Electricity Engineers' Association (EEA) has produced a guideline which has similar principles. These security standards are consistent with industry best practice and are 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
- Increase asset utilisation.

These security standards accept a small risk that customer supplies may be interrupted when a network fault occurs during peak demand times[11]. 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

[10] Frequency is a measure of how often breaches of the security standards are likely to occur. Consequences are a measure of the health and safety, reputation, customer impact and financial risk to Wellington Electricity of not addressing the problem

[11] A true deterministic standard, such as N-1, implies that supply will not be lost after a single fault at any time. The Wellington Electricity security 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 required asset capacity and redundancy levels become possible.

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.

Type of Load	Security Criteria
CBD	N-1 switching[2], for 99.5% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Mixed commercial / industrial / residential substations	N-1 switching[1], for 98% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Predominantly residential substations	N-1 switching [1] for 95% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.

Figure 5-1 Security Criteria for the Subtransmission Network

Type of Load	Security Criteria
CBD or high density industrial	N-1 switching [2] for 99.5% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Mixed commercial / industrial / residential feeders	N-1 switching [3] for 98% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Predominantly residential feeders	N-1 switching [3] for 95% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Overhead spurs supplying up to 1MVA urban area	Loss of supply upon failure. Supply restoration dependent on repair time.
Underground spurs supplying up to 400kVA.	Loss of supply upon failure. Supply restoration dependent on repair time.

Figure 5-2 Security Criteria for the Distribution Network

1: A brief supply interruption of up to 5 minutes may occur following an equipment failure while the network is reconfigured.

2: A brief supply interruption of up to 1 minute may occur following an equipment failure while the network is automatically reconfigured.

3: In areas other than the CBD an operator may need to travel to the fault location to manually operate network switchgear, in which case the supply interruption could last for up to 1 hour.

While the reliability of the Wellington Electricity distribution system is high, notwithstanding the difficult physical environment in which the system must operate[12], it is uneconomic generally to design a network where supply interruptions will never occur, except where the consumer is willing to pay more for a specific supply. Hence the network is designed to limit the amount of time over a year when it is not possible to restore supply by reconfiguring the network following a single unplanned equipment failure. This approach recognises that the electricity demand on the network varies according to the time of day and season of the year, and that the time over which the system is exposed to its peak demand is very small during the course of a year. It also recognises that equipment must at times be taken out of service for planned maintenance and that, when this occurs, parts of the network are exposed to a lower level of security and, as a consequence, the potential for a higher risk of interruption. The security criteria and assumptions detailed above also highlight that some areas are supplied by spur lines, as this is the most efficient supply configuration, and these areas will lose supply on failure until the repair is completed. Network planning guidelines indicate how much load will be supplied by spur lines and determine at which point additional supplies or back feed points are considered for a supply area.

Wellington Electricity's network design and asset management systems also have regard for the time taken to restore supply following an interruption. When an unplanned equipment outage does occur, considerable effort is made to restore supply to customers not directly affected by the equipment fault by switching load to other parts of the network. However at times of peak demand, or where equipment is out of service for maintenance at the time of the unplanned outage, it may not be possible to switch all load in this way and maintain supply quality. In these cases an extended outage may occur with maximum restoration times as shown in Figure 5-1 and Figure 5-2.

The criteria generally do not apply to the low voltage network or to failures of connection assets used to supply individual customers, which are usually designed for 'n' security. In such situations an interruption will last for the time taken to make a repair.

The criteria also do not apply when multiple equipment outages affect the same part of the network or when major storms or other severe events have a high impact on the system and can stretch the capacity of Wellington Electricity or its contractors to respond in a timely manner. Wellington Electricity has emergency plans in place to prioritise response and repair efforts to assist mitigating the impact of such situations but when they occur, longer supply interruptions than shown in the tables are possible.

5.5. Capacity of New Plant

When planning an augmentation to the network to increase its existing capacity, it is necessary to determine the capacity of the new equipment to be purchased and installed. This often involves a trade-off between cost and the size of the increased capacity and the growth expected over the asset's service life because:

- If the capacity is too large either Wellington Electricity or its consumers have to pay the cost of any capacity that will not have been economically utilised before the equipment reaches the end of its economic life

[12] Much of Wellington Electricity's supply area is renowned for its high winds. There can also be a high concentration of salt in the atmosphere, blown in from the sea.

- If the capacity is too small then premature asset replacement will be required and this generally increases costs.

Determining the optimum capacity is made more difficult by the fact that the economic life of most primary distribution assets is between 40 and 60 years and the difficulty of forecasting electricity demand over this period into the future other than from underlying growth averages.

Wellington Electricity uses the Commerce Commission's 10 year planning period as the starting point for making equipment capacity decisions and then takes the following into consideration:

- On the basis of the current load forecast, determine the maximum potential load on the equipment at the end of the planning period under the most severe operating condition that the network is planned to withstand
- Select the next highest standard equipment size as identified in Figures 5-3 to 5-5.

5.5.1. 11kV Switchgear

Application	Standard Ratings	Fault Rating
Zone incomer circuit breaker	1200A, 2000A	25kA
Zone feeder circuit breaker	630A	25kA
Dist feeder circuit breaker	630A	20kA
Dist transformer circuit breaker	200A	20kA
Ring main unit	400A minimum	20kA

Note 1: These are manufacturer's standard ratings.

Note 2: Existing equipment may have ratings different from those listed in the table.

Figure 5-3 Standard Ratings for 11kV Switchgear

5.5.2. 11kV Cable

Application	Standard Ratings
Feeders – backbone	300A minimum
Feeders – branch	200A minimum
Dist transformer	Match transformer

Note 1: Larger cable ratings may be employed on a case by case basis.

Figure 5-4 Standard Ratings for 11kV Cable

5.5.3. Distribution Transformers

Standard Ratings (kVA)
15, 30 50, 100, 200, 300, 500, 750, 1000
1500kVA upon request for special customer projects

Note 1: All distribution transformers: 11kV/400V delta-wye.

Note 2: These are manufacturer's standard ratings.

Figure 5-5 Standard Ratings for Distribution Transformers

It is important to note that this is only a starting point for making capacity decisions. An engineering and economic judgement is then made as to whether this size is appropriate taking other factors into account. Such factors include:

- Compliance with the network security criteria
- Margin between the required capacity and the next highest standard size
- Incremental cost of different equipment sizes
- Forecast rate of demand growth
- Back-up capacity to adjacent areas

5.5.4. 11kV Feeders

Most of the 11kV feeders in the Wellington CBD and in some locations around Wellington eastern suburbs and the Porirua commercial centre are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of security and hence a high level of supply reliability. The 11kV network outside the Wellington CBD, in Wellington suburban areas, Porirua and Hutt Valley, typically comprises radial feeders with a number of mid feeder switchboards with circuit breakers. The radial feeders normally open interconnectors to other feeders so that, in the event of an equipment failure, supply to customers can be switched to neighbouring feeders. To allow for this, distribution feeders are not operated at their full thermal rating under normal system operating conditions. The feeder utilising factor at which Wellington Electricity currently operates the distribution feeders during normal and contingency operation is identified in the table below.

Feeder Operation	Normal Operation Loading (%)	Contingency Operation Loading (%)
Two Feeder Mesh Ring	50	100
Three Feeder Mesh Ring	66	100
Four Feeder Mesh Ring	75	100
Five Feeder Mesh Ring	80	100
Radial Feeder	66	100

Figure 5-6 11kV Feeder Utilisation during Normal and Contingency Operation

In certain cases consumers may desire a level of security above that offered by a standard connection. Should this arise, Wellington Electricity will offer a range of alternatives that provide different levels of security at different prices (price/quality trade off). The customer can then choose to pay for a higher level of security to meet their needs for the load they are being supplied.

Given the relatively modest demand growth in its supply area, it is unlikely that Wellington Electricity would expose itself to optimisation risk by installing asset capacities greater than indicated by the above approach. Where specific customers request higher capacity levels than Wellington Electricity would typically provide, these can be provided subject to a satisfactory commercial arrangement.

5.6. Asset Standardisation and Design Efficiencies

5.6.1. Asset Category Standardisation

Distribution network equipment such as transformers, ring main units, low voltage distribution and are all selected from manufacturers standard product ranges to ensure that procurement costs are minimised (compared with custom designs). Materials and equipment are specified in the Approved Network Fittings standard, as well as individual technical specifications. In some cases Wellington Electricity will commission the design of custom equipment to reduce overall costs (such as a special transformer design to fit on an existing concrete pad, which although slightly higher to purchase, is significantly cheaper to install). Wellington Electricity is also reviewing all the construction standard designs to ensure there is consistent construction across the entire network regardless of the build contractor.

Zone substation equipment is generally less standardised due to the more specific nature of this equipment, however in the past few large projects, items such as protection relays, circuit breakers, batteries, chargers and communications equipment has been of the same type.

Asset standardisation also leads to a reduced requirement for a range of spares to be held, and also allows field and engineering staff to become familiar with a common range of equipment which allows for efficiencies in installation, maintenance, repair and operation.

5.6.2. Approach to identify standard designs

Wellington Electricity has standard design and planning principles for the distribution system for system elements which are of low complexity and of a repetitive nature (i.e. pole replacement, distribution substation installations), as detailed in section 5.5 above, as well as a range of standard substation design components, for example:

- Standardised SCADA/Communications panels
- DC supply panels, battery banks and stands
- Common protection element designs (SEL-751A, Siemens 7SD610, Solkor)
- Use of a selected range of switchgear for commonality across substations.

Wellington Electricity has a range of standard construction designs for earthing and low voltage distribution design, and is working towards developing standardised pole selection charts for routine pole replacement (pole assembly standard designs already exist).

5.6.3. Energy Efficiency

Wellington Electricity aims to improve energy efficiency in the operation of the network and to reduce losses on the system. Wellington Electricity looks forward to working with the Commerce Commission on incentives for investment in this area that could be introduced under section 54Q of the Commerce Act.

The following considerations are made:

- Network planning – to design systems which do not lead to high losses or inefficient conveyance of electricity (i.e. to select the correct conductor types and operating voltages) with a view on total cost of ownership models across the lifecycle of the asset.

- Equipment procurement – to select and approve the use of equipment which meets recognised standards, for example distribution transformers to meet recognised AS/NZS standards. For large items such as zone power transformers, the purchase decision includes lifecycle loss calculations (copper and iron) to determine economics of different units offered.

- Network Operations – to operate the network in the most efficient manner available given current network constraints, and to utilise the load management system to optimise the system loadings (which in turn affect efficiency of the network).

5.7. Demand Forecasts

5.7.1. Methodology

Loads on individual feeders and zone substations are captured by the SCADA system while the load at each GXP is metered through the time of use revenue metering. This information allows Wellington Electricity to trend actual demands at the GXP, zone substation and feeder level and to project these trends into the future using an extrapolation analysis model.

Demand forecasting is carried out using a 'bottom up' approach, starting at the zone substation level. The first stage of this process involves extracting historical load data from SCADA. The load data is then graphically analysed and any uneven spikes or peaks replaced with an average value derived from five days before and after the period of abnormal demand.

The method used to determine the peak demand is a sustained loading that lasts for two hours and occurs at least five times during the year. This differs from the maximum load, which may occur only momentarily for 30 minutes or less, or as a result of abnormal system operations, and does not impact upon system ratings.

After calculating the peak demands from actual load data, future year loads are found by extrapolating the historical data into the future, to extent of the 10 year planning horizon. Known step changes are then applied to the forecasts. These steps may be the result of:

- System reconfigurations where load has been moved between substations
- Major developments that introduce large new loads onto the network
- Changes to the Wellington Electricity load control system
- New electricity generation that is expected to affect peak demand
- Load reductions caused by movement of businesses or the closure of businesses.

A subjective review of the load forecasts for each zone substation is then undertaken. This comprises a check of the forecasts against local knowledge of network developments. Reviewers of the forecasts will include project managers and customer service staff who have a good overview of customer connection trends and who have regular communication and consultation with key customers, developers and councils. Property developers and businesses may also be canvassed for information on plans that may result in introducing new loads to the network. Forecasts are modified if necessary to reflect this local knowledge. The zone substation load forecasts are then 'rolled-up' to the GXP level, taking diversification factors into consideration as the peak zone substation demands may not always occur at the same time as each other.

The Wellington Electricity 'bottom up' GXP forecasts are then compared to Transpower's 'top down' GXP forecasts. It is understood that Transpower's forecasts are derived from the national load and energy forecasts which take into account economic and population growth indicators. While this forecast is usually accurate at the national level, it can be difficult to break the national growth down to the GXP level which in turn can lead to discrepancies with 'bottom up' forecasts. Any significant differences between the two forecasts are investigated and addressed or explained.

Detailed forecasts for the planning period are provided in the next sections. They indicate that forecast growth in Wellington Electricity's supply area is relatively low when compared to demand growth in many parts of the country, and this is supported when compared to figures provided by the NZ Institute of Economic Research. The methodologies used by Transpower differ from Wellington Electricity's method and overstate the demand and growth at GXP level in Wellington. Table 5-7 provides the overall Wellington Electricity network peak demand forecast.

Wellington Electricity bases the load forecasts on the assumption of the normal use of load control to manage peak load periods. In the future, if the ownership of rights to controllable load change, and Wellington Electricity can no longer manage peak demand periods using ripple based load control, these forecasts may differ. Loads may be switched by other parties causing irregular localised or system wide peaks which will affect network demand and quality of supply.

Network	System Maximum Demand MVA [2] (including DG)										
	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Wellington Electricity	552	557	562	567	573	578	583	589	594	600	605

Figure 5-7 Network Demand Forecast

5.7.2. GXP Demand Forecast

The actual and forecast demand at each GXP supplying Wellington Electricity's distribution network is shown below.

GXP	Actual and Forecast System Maximum Demand MVA [2] (including DG)										
	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Central Park 33 kV	171.4	174.0	176.6	179.2	181.9	184.6	187.4	190.2	193.1	196.0	198.9
Central Park 11 kV	17.5	19.8	20.1	20.4	20.7	21.0	21.3	21.6	22.0	22.3	22.6
Gracefield 33kV	51.8	58.5	59.3	60.0	60.7	61.5	62.3	63.1	63.8	64.6	65.4
Haywards 33 kV	14.9	15.1	15.4	15.6	15.8	16.1	16.3	16.5	16.8	17.0	17.3
Melling 33 kV	45.0	46.8	47.1	47.5	47.9	48.2	48.6	48.9	49.3	49.7	50.1
Pauatahanui 33kV	19.5	19.7	19.9	20.2	20.4	20.7	21.0	21.2	21.5	21.8	22.0
Takapu Road 33 kV	92.0	93.2	94.3	95.5	96.7	97.9	99.1	100.4	101.6	102.9	104.2
Upper Hutt 33 kV	31.0	31.5	32.1	32.7	33.2	33.8	34.4	35.0	35.6	36.2	36.9
Wilton 33 kV	52.0	52.6	53.1	53.6	54.2	54.7	55.2	55.8	56.4	56.9	57.5
Kaiwhara'11 kV [1]	35.0	35.5	36.1	36.6	37.1	37.7	38.3	38.8	39.4	40.0	40.6
Haywards 11 kV	21.5	21.8	22.1	22.5	22.8	23.1	23.5	23.8	24.2	24.6	24.9
Melling 11 kV	24.2	26.5	26.9	27.2	27.5	27.9	28.2	28.6	28.9	29.3	29.7

1: Kaiwharawhara GXP has a summer peak. All other GXPs have a winter peak.

2: Base MD value for the projection is the actual for the year ending 31 December 2012.

3: Demand reduced on Central Park 33kV GXP due to load transfer from Frederick Street to Nairn Street zone substation.

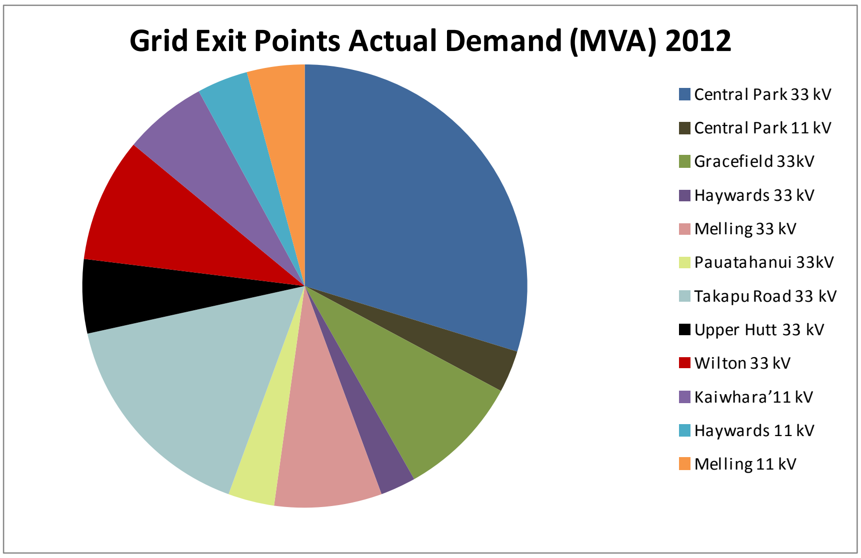

Figure 5-8 Network Demand by GXP - 2012

5.7.3. Zone Substation Demand Forecasts

Zone substation	Actual and Forecast Demand (MVA, Calendar year)										
	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
8 Ira St	17.0	17.3	17.5	17.8	18.0	18.3	18.6	18.9	19.2	19.4	19.7
Brown Owl	15.5	15.7	15.9	16.1	16.3	16.5	16.7	16.9	17.2	17.4	17.6
Evans Bay	15.8	16.1	16.3	16.6	16.9	17.2	17.5	17.8	18.1	18.4	18.7
Frederick St	29.2	29.7	30.2	30.8	31.3	31.9	32.5	33.0	33.6	34.3	34.9
Gracefield	12.6	12.8	13.0	13.1	13.3	13.5	13.7	13.9	14.1	14.3	14.5
Hataitai	17.6	17.8	18.0	18.2	18.5	18.7	18.9	19.1	19.4	19.6	19.8
Johnsonville	18.2	15.5	15.8	16.1	16.4	16.7	17.0	17.3	17.6	17.9	18.2
Karori	17.3	17.5	17.8	18.0	18.3	18.5	18.8	19.1	19.3	19.6	19.9
Kenepuru	11.0	11.4	11.7	12.1	12.4	12.8	13.2	13.5	13.9	14.3	14.6
Korokoro	11.9	18.5	18.8	19.0	19.2	19.4	19.7	19.9	20.2	20.4	20.6
Maidstone	15.0	15.2	15.4	15.6	15.9	16.1	16.3	16.5	16.8	17.0	17.2
Mana-Plimmerton	18.9	19.2	19.5	19.7	20.0	20.3	20.6	21.0	21.3	21.6	21.9
Moore St	25.4	26.1	26.8	27.5	28.2	28.9	29.6	30.3	31.1	31.8	32.5
Naenae	15.5	15.7	15.9	16.1	16.3	16.5	16.7	17.0	17.2	17.4	17.6
Nairn St	17.5	19.8	20.1	20.5	20.8	21.2	21.5	21.9	22.3	22.7	23.0
Ngauranga	12.8	13.0	13.1	13.3	13.5	13.7	13.8	14.0	14.2	14.4	14.6
Palm Grove	27.5	27.9	28.4	28.8	29.3	29.8	30.2	30.7	31.2	31.7	32.2
Petone	10.5	10.6	10.8	10.9	11.1	11.2	11.3	11.5	11.6	11.8	11.9
Porirua	17.7	17.9	18.2	18.5	18.7	19.0	19.2	19.5	19.8	20.1	20.3
Seaview	13.4	15.0	15.2	15.4	15.6	15.8	16.0	16.2	16.4	16.7	16.9
Tawa	14.3	14.9	15.3	15.9	16.4	17.0	17.5	18.0	18.5	19.1	19.6
The Terrace	29.7	30.2	30.7	31.1	31.6	32.2	32.7	33.2	33.7	34.3	34.8
Trentham	14.9	15.1	15.3	15.5	15.8	16.0	16.2	16.4	16.7	16.9	17.1

Zone substation	Actual and Forecast Demand (MVA, Calendar year)										
	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
University	25.8	26.3	26.7	27.2	27.7	28.2	28.7	29.2	29.8	30.3	30.8
Waikowhai	16.2	16.3	16.5	16.6	16.8	17.0	17.1	17.3	17.5	17.7	17.8
Wainuiomata	17.0	17.2	17.4	17.7	17.9	18.1	18.4	18.6	18.9	19.1	19.3
Waitangirua	14.8	15.0	15.1	15.3	15.5	15.6	15.8	16.0	16.2	16.3	16.5
Waterloo	18.0	18.3	18.5	18.8	19.0	19.3	19.6	19.8	20.1	20.4	20.7

Note 1: Smoothed actual demands are used for zone substation forecasts because short term peaks that result from operational switching of loads between substations can give a misleading impression of 'normal' loads.

Figure 5-9 Zone Substation Demand Forecast

5.7.4. High Load Growth Areas

Outside the Wellington CBD, there are few areas of high load growth due to the closure of major industry and low levels of residential development. In relatively limited areas there is high loading on parts of the system, such as in the suburbs of Johnsonville and Churton Park as a result of housing developments over the past 10 years. These areas of the network are at capacity and require investment within the planning period. Residential subdivision is continuing in these areas as detailed later in this section. Moderate load growth is also forecasted in the Porirua area, especially the Aotea subdivision and proposed subdivision plans north of Plimmerton, as well as continuing development in the Whitby area. There are a small number of growth industries in the Wellington region, particularly businesses supporting the international film industry. In most parts of the network however, growth is below NZIER forecasts and, at a system wide level, growth and energy volumes have declined in the past two years. The level of load growth considered to be moderate to high on the Wellington network is still low by national standards.

5.7.4.1. Wellington CBD

Load growth is high in parts of the Wellington CBD with a growth rate of around 3.0% resulting from moderate sized step change loads. The main high load growth areas in the Wellington CBD are Wellington Central, Thorndon, Newtown and Te Aro. This growth is largely through the construction of new buildings with high load densities, with many of these having dedicated transformer capacity of 750kVA or greater. The demand in the CBD area is supplied by Frederick Street, The Terrace, Moore Street and Palm Grove zone substations. Currently The Terrace and Frederick Street zone substations are now very highly loaded, compared with other substations in the network, as a result of gradual increases over time. With no new zone substation capacity installed in over 25 years, this presents a constraint on the network. Most of the load demand in the CBD area is supplied by a meshed 11kV system with multiple feeds from a zone substation. As load within the CBD rises, the ability of the meshed system to respond to a single fault or event deceases as the loading on the remaining feeders may cause overloads, potentially leading to cascade tripping on feeders. Such overloading issues will need to be addressed within the short to medium term. There is discussion of this matter further on in this section.

5.7.4.2. Porirua

The Aotea subdivision has been highlighted as an area of high growth and high demand which is planned to be supplied from the Porirua zone substation. The Porirua zone substation has spare capacity at present and by undertaking reinforcement of Porirua feeder 2 (presently a spare feeder) would be able to supply the future load increase at Aotea subdivision, without requiring substation level reinforcement during the planning period. The Porirua feeder reinforcement work would require replacing the overhead section of this feeder with underground cables. Such work will be driven by the customer because the overhead section of this feeder runs across the proposed subdivision land. Some of this demand growth at subdivision level is configured as an embedded network owned by others and the tariffs recovered do not always fully reflect the level of investment required to supply such loads.

5.7.4.3. Upper Hutt

There is the possibility of high load growth north of Upper Hutt due to a proposed development at Maymorn, with an expected 1,800 dwellings being built over the next 10 years should Council re-zoning go ahead. Reinforcement of the 11kV system in this area, supplied from the Brown Owl zone substation, would be required. This future step load increase has not been included in the forecast because the Upper Hutt City Council has not confirmed the time frame for this project and also the stages in which this will commence. Initial public consultation met with resistance which indicates this project may not eventuate within the current planning period.

It is expected that there will be moderate load growth in the industrial area of Upper Hutt currently supplied by the Trentham zone substation, as large, affordable sites are being developed for data centres and other high density loads. This load however can largely be accommodated by existing infrastructure which has been underutilised since the closure of vehicle assembly and tyre manufacturing plants in this area.

5.7.5. Low Load Growth Areas

With the exception of the areas identified above, load growth is low in most parts of Lower Hutt, Upper Hutt and Porirua. The load growth rate is below the national average, with some suburbs around 0.70% to 1.3% growth, and declining loads in others. The overall effect is a system decrease in both demand and volumes over the past two years. The distribution network is less constrained in these areas with adequate capacity and security to meet demand during normal operation and contingency events. The load growth in these areas is expected to follow historical trends with few constraints arising during the planning period.

Due to low load growth in the Lower Hutt region, especially at Petone, Korokoro and Seaview zone substations, the current asset utilisation at these substations is low. The poor asset condition, high asset age and low forecast load growth rate at the Petone zone substation provides an option for asset rationalisation. This would be subject to capital maintenance allowances within the Default Price Path and permanently transferring load to interconnecting neighbouring substations rather than replacing the aged asset.

5.7.6. Step Load Changes

Wellington Electricity has identified the following new major loads that may occur over the next year. The loads which are certain have been incorporated into the demand forecasts for the network as described in the previous section.

Anticipated Start Date	Likely Peak Demand (MW)	Expected Load Factor (%)	Type of Demand	GXP	Likelihood
2013/14	2.0	0.2	Residential	Central Park	Certain
2013/14	0.2	0.2	Residential	Gracefield	Certain
2013/14	3.0	0.2	Commercial	Haywards	Certain
2013/14	1.0	0.2	Residential	Pauatahanui	Certain
2013/14	2.0	0.35	Commercial	Takapu Road	Certain
2013/14	1.0	0.25	Residential	Takapu Road	Certain
2013/14	2.0	0.3	Residential	Upper Hutt	Most Likely
2013/14	5.0	0.35	Commercial	Central Park	Most Likely
2013/14	2.0	0.35	Commercial	Gracefield	Most Likely
2013/14	0.2	0.35	Commercial	Melling	Likely
2013/14	4.0	0.35	Commercial	Upper Hutt	Likely
2013/14	0.5	0.35	Commercial	Wilton	Possible

Figure 5-10 New Step Change Loads Identified for 2013/14

Wellington Electricity has also identified the following loads which may occur in future years, where the timing and certainty are less well known.

Likely Demand Beyond 2013/14 (MW)	Expected Load Factor (%)	Type of Demand	GXP
4.0	0.35	Commercial	Haywards
6.0	0.35	Commercial	Upper Hutt
0.75	0.2	Residential	Pauatahanui
0.35	0.2	Residential	Upper Hutt
0.40	0.2	Residential	Takapu Road
1.0	0.35	Commercial	Gracefield
1.0	0.35	Commercial	Takapu Road
0.5	0.35	Commercial	Melling

Figure 5-11 New Step Change Loads Identified Beyond 2013/14

5.7.7. Embedded Generation and Demand Control

The load forecast figures provided in this section are inclusive of any embedded generation and demand control operating at the time of the calculated peak. Further detail on embedded generation and demand control is presented under separate headings in this section.

5.8. Network Development – Options Available

The process that Wellington Electricity follows when analysing major network investment opportunities includes the long listing of options developed in accordance with the planning criteria outlined earlier in this section. The long list represents a range of possible solutions to address a clearly defined investment need. The long list of options will be relatively similar for most of the investment opportunities that occur on the network and projects will usually fall under one or more of the following headings:

- Do nothing (status quo)
- Network solutions such as:
  - Redistributing demand (e.g. network reconfiguration)
  - Reinforcing the network (this may include many sub-options)
- Non-network solutions such as:
  - Reducing network demand (e.g. energy efficiency, load control, demand side initiatives)
  - Installing generation (e.g. distributed generation)

Non-network solutions are discussed in more detail in the following sections.

Each long listed option will have a cost estimate associated with it, a benefit in terms of how it addresses the need for reinforcement and an assessment of its feasibility. The long list will be ranked using the above criteria (i.e. cost, benefit and feasibility) in order to allow for a short list of options to be developed. The short list will typically be limited to two or three options that have roughly similar cost, benefits and feasibilities. The individual projects, and options for each project, are prioritised using the project prioritisation methodology described in section 5.2.

The implementation of this part of the network investment process is under continuous review. Once the process is embedded, major investment projects will each have associated with them a long list of alternatives that had been considered.

5.9. Distributed Generation Policy

There is already a small but significant amount of generation embedded within the network. Wellington Electricity welcomes enquiries from third parties who are interest in installing embedded generation. Where it is identified that a third party scheme may have the potential to defer the need for capital investment on the network, the following aspects will be considered:

- The risk of non-provision of service needs to be managed. There is little point in paying a third party for a service such as generation or load reduction if the service cannot be guaranteed at the time that the network demand is at a peak
- The service must comply with relevant technical codes and not interfere with other consumers
- Any payments made to third parties must be linked directly to the provision of a service that gives the required technical and commercial outcomes
- Commercial arrangements must be consistent with avoided cost principles

- Commercial agreements must be reached on other issues not directly related to any benefit provided to Wellington Electricity. These can include the cost of connection and payment of use of network charges.

If the issues above can be managed, and the despatch of generation can be co-ordinated with system peaks or constraints, then the use of embedded generation as part of a demand side management programme could bring real benefits to Wellington Electricity. The reduction of load in constrained parts of the network such as the CBD could defer network investment that may be required within the planning period.

Wellington Electricity has developed a distributed generation connection policy and has different procedures for the assessment and connection of distributed generation up to 10kW and over 10kW. These are in line with the Electricity Industry Participation Code 2010, Part 6..

Information about connecting Distributed Generation is available on the Wellington Electricity website – www.welectricity.co.nz or by calling 0800 248 148.

5.10. Non-Network Solution Policy

Wellington Electricity's load control system is already used to manage peak demands on the network and therefore has the effect of deferring demand driven system augmentation. Wellington Electricity's tariff structure provides benefits if retailers mirror the pricing structure to provide an incentive for consumers to shift electricity consumption away from periods of peak network demand. The load control system provides significant benefits to the network by reducing peak demand and moving it to the off peak periods. This has resulted in the significant deferral of network investment as well as providing an effective means of dealing with network loading during outages.

Other non-network solutions may include demand response, where consumers may be given an incentive to switch off demand at certain times when the network is approaching a period of constraint. For Wellington Electricity, the type of demand that may prove useful in deferring network investment is air conditioning plant in the CBD. Demand response is less likely to provide benefit in suburban areas as the loads are diluted amongst a large number of consumers and the load control system already provides a similar benefit.

Wellington Electricity has not pursued demand response to date because the load control system is so effective. Demand response will however be included as a long list option in any major network investment options analysis where it may be useful. Should it prove to warrant further investigation as a way of meeting the needs of an investment opportunity in the short term, then Wellington Electricity will pursue it accordingly. Notwithstanding this, a non-network solution policy that includes demand response will be developed over the longer term as Wellington Electricity progresses with establishing such systems and processes. Opportunities may exist under provisions in the Commerce Act however these options will need to be guided by the Commerce Commission.

5.11. Emerging Technologies and Practices

In recent times there has been much industry excitement around so called "smart grids" and smart technologies that will find their way into transmission and distribution networks, the metering and retail space, as well as at consumer level within homes and businesses.

As the topic is largely undefined and there are many different technologies emerging, Wellington Electricity is not actively pursuing smart grid projects or trials. By design, the Wellington Electricity network has a large number of features that may now be considered to be part of a “smart network”. Such features include closed ring feeders with differential protected zones that trip out leaving healthy sections in service, on demand load control via the existing ripple control system, and a widely SCADA-ised network with over 230 sites offering remote control and indication.

To develop and maintain the network that Wellington Electricity presently operates in parts of the Wellington City area, providing a higher level of reliability than a conventional radial network requires a higher return to cover the higher costs of assets utilised. The price-quality trade off made now for the level of technology means that future increases to price to improve quality may be less than if this technology was not presently being used.

As new technologies emerge that may improve the ways in which Wellington Electricity may design, build, maintain or operate the network, they will be thoroughly investigated. There is also access to considerable intellectual property and learnings through the wider group of CKI companies across Australia, Hong Kong and the United Kingdom where the outcome of investigations into best practice and trials of new technology can be shared with Wellington Electricity and considered in a local context. New technologies will be implemented if the benefits to the network and stakeholders meet or exceed any additional costs incurred by installing and using them. Wellington Electricity specifies equipment which can in future be used with future technologies where it is practicable to specify at this time. Wide scale replacements of existing assets with new technology capable equipment is not economic and it will be introduced as existing assets reach their end of life or are replaced due to a requirement for a change in capacity or functionality.

5.12. Grid Exit Points - Constraints and Development Plans

The table below provides GXP capacities and forecast demands for the beginning and end of the forecast period. Figure 5-12 provides an indication of loadings on the GXPs.

GXP	Installed Transformers (MVA)	Cyclic n-1 Capacity (MVA)	System Maximum Demand MW [2] (including DG)	
			2013	2022
Central Park 33 kV	2x100 + 1x120	228	174.0	198.9
Central Park 11 kV	2x25	30	19.8	22.6
Gracefield 33kV	2x85	89	58.5	65.4
Haywards 33 kV	1x20	0	15.1	17.3
Haywards 11 kV	1x20	0	21.5	24.9
Melling 33 kV	2x50	52	46.8	50.1
Melling 11 kV	2x25	32	26.5	29.7
Pauatahanui 33 kV	2x20	22	19.7	22.0

GXP	Installed Transformers (MVA)	Cyclic n-1 Capacity (MVA)	System Maximum Demand MW [2] (including DG)	
			2013	2022
Takapu Rd 33 kV	2x100	92	93.2	102.9
Upper Hutt 33 kV	2x37	37	31.5	36.9
Wilton 33 kV	2x100	106	52.6	57.5
Kaiwharawhara 11 kV	2x38	41	35.5	40.6

Figure 5-12 GXP Capacities

The stacked line graph below provides the coincident peak demand forecasts for all GXPs.

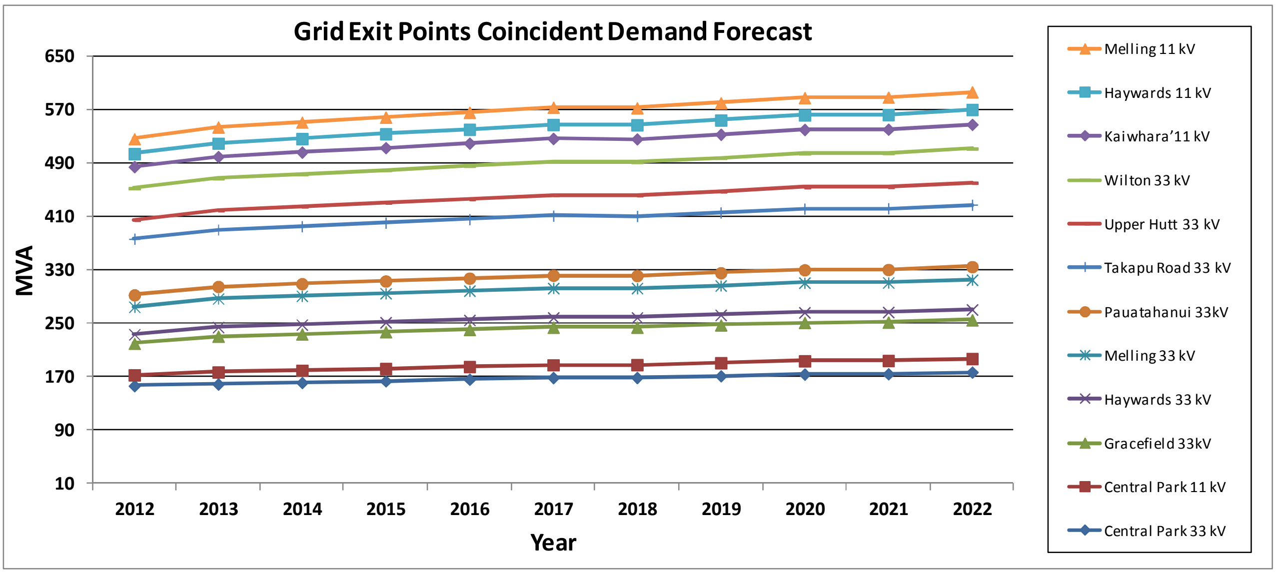

Figure 5-13 GXP Coincident demand forecast

5.12.1. Central Park and Wilton Constraints

As indicated in Section 3 (Assets Covered), the Central Park GXP has the highest peak demand in the Wellington Electricity network.

There are three 110kV circuits from Wilton which supply three transformers (110/33 kV) at Central Park as shown in figure 5-14. All three 110kV circuits into Central Park are supplied from the 110kV bus at Wilton and which is supplied by a single 220/110kV transformer (T8) and two 110kV circuits from Takapu Road GXP as shown in 5-15. The West Wind wind farm connects into the double 110kV circuit to Central Park and is not considered as permanent source of supply due to intermittent supply output so cannot be factored into demand or security analysis. In addition, the tee configuration adopted by Transpower can impact on reliability of the 110kV circuits.

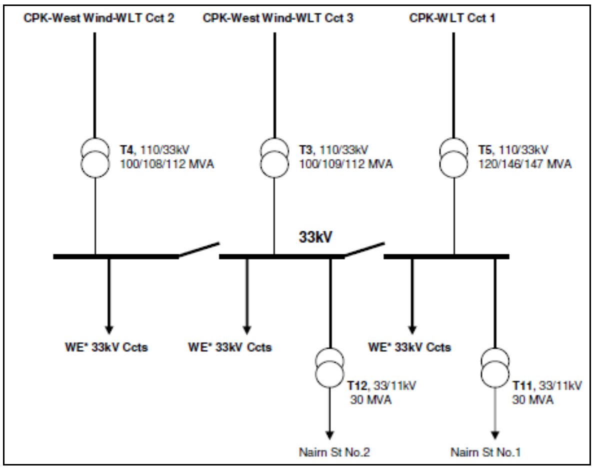

Figure 5-14 Central Park GXP Layout

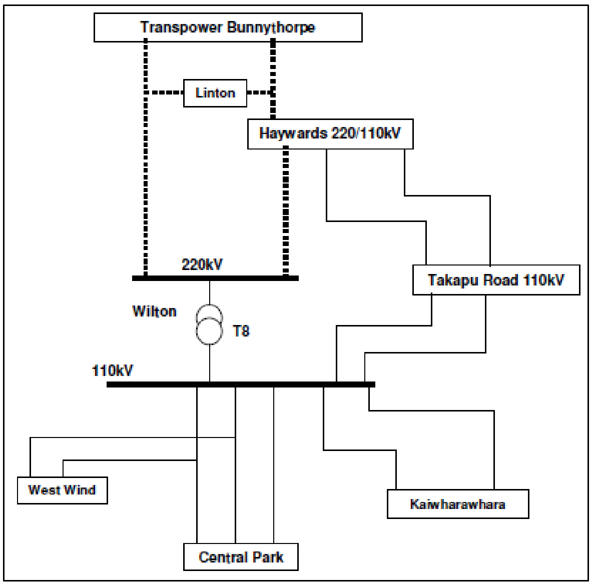

Figure 5-15 Transpower 220 & 110kV Network supplying Wellington Network layout

Due to there being no 110kV bus at Central Park, all three 110kV circuits are transformer feeders with Wilton circuit 1 supplying T5 (120MVA), Wilton circuit 2 supplying T4 (100MVA) and Wilton circuit 3 supplying T3 (100MVA). Should there be a double 110kV circuit outage, it is not possible to supply the entire Central Park load by the single remaining 110kV circuit from Wilton. As a result the security of supply to Central Park GXP is not true N-1 as System Operator rules limit the loading of the remaining circuits when one circuit is out of service.

There are operational constraints at Central Park which restrict the N-1 capacity of the 33kV system to 109 MVA due to having no 110kV bus at Central Park, and a requirement imposed by the System Operator to limit the post-contingency loading to the rating of a single 110kV branch. Load management would be required to prevent transformer overloading in this configuration in the event of a second circuit tripping, which reduces the permissible loading of the 33kV system to 109 MVA. In late 2010 a Special Protection Scheme (SPS) was installed at Central Park GXP to provide the load management automatically should one 110kV circuit or transformer be out of service, and the remaining load be shared by two transformers.

Wellington Electricity has raised a high level request (HLR) for an investigation into options for addressing the capacity issue with Transpower. Discussions on the outcome from the HLR and possible solutions are underway between Transpower and Wellington Electricity. This will also include discussions on the security need for an 110kV bus to alleviate the requirements for controlled load drop during contingencies. Due to the location of Central Park GXP, the type of load served and the risk associated with a loss of supply from this site, as well as the space constraints faced developing substations within the Wellington City area, close liaison has occurred between Wellington Electricity, Transpower and the Wellington City Council to develop a shortlist of workable solutions which the Council will be able to assist with implementing through zoning and land use decisions.

The three key issues Wellington Electricity faces with the Central Park GXP are:

1. Post contingency rating limit – as described above there is a requirement to have an SPS and controlled load shedding in the event that two of three transformers are out of service at this site. The SPS is required to be armed in the event that one transformer is unavailable.

2. Diversity of supply from this site – as the largest GXP in the Wellington Region, supplying over 170MW of load, there is a significant risk should the incoming circuits and transformers be unavailable for service, or in the event of a major 110kV bus fault at Wilton, or a complete loss of the Central Park GXP site due to fire, asset failure, or natural disaster. With the large programme of gas cable replacement over the planning period, certainty around configuration of connection points would allow an optimised capital investment on renewal of these assets.

3. Capacity for load growth in the CBD – there is a requirement to build a new zone substation in the Wellington CBD area within the planning period and given geographic constraints, supply from Central Park is the more sensible option (the cost, route and length would make installing 33kV circuits back to the Wilton GXP impractical). Given the high loading and low diversity, Wellington Electricity does not wish to connect more load (potentially another 20MVA) into this the Central Park GXP.

The assets described above at Central Park and Wilton are owned by Transpower. Any reinforcement to mitigate these constraints is undertaken by Transpower with the capital cost charged as a New Connection investment to Wellington Electricity, who in turn pass this cost through to customers over a fixed period (typically up to 20 years). Wellington Electricity needs to drive Transpower to address the security of supply risks identified in the three key issues.

Transpower is currently preparing a proposal to replace the two 109MVA transformers with 120MVA transformers to address asset condition risk. While this will provide benefit in the form of additional capacity it is still insufficient to address N-1 operational load restrictions.

5.12.1.1. Prospective Options to Eliminate Constraints at Central Park and Wilton

There are few options available to mitigate the security of supply risks identified in the three key issues above.

<u>Option 1: Do nothing</u>

This option is not recommended as the existing constraints could cause a significant interruption of supply to the Wellington CBD and a large number of residential consumers in the Wellington City area. The social and economic consequence of this is generally unacceptable to the people of Wellington. Smaller outages on the transmission system in recent years, lasting only hours, have generated national media interest and been criticised by Wellington consumers, especially those within the business community. A sustained outage due to a major component failure would be disastrous for the Wellington economy.

Option 2: Reconfiguration of 110kV circuits and installation of a 110kV bus at Central Park

The operational constraints at Central Park GXP could be reduced by installing a 110kV bus. Installation of a 110kV bus would remove the requirement for any type of load management plan or special protection scheme to be utilised should one 110/33kV transformer be out of service. This option will provide more operational flexibility at Central Park without compromising the reliability of the network. However before running the proposed 110kV bus closed at Central Park GXP, the line impedance of the existing three 110kV circuits should be considered and issues mitigated as the three incoming circuits are of different construction.

Installation of a 110kV bus at Central Park will not completely eliminate the risks of supply security into the Wellington CBD as a residual issue exists on the 110kV supply circuits. Although of lower likelihood than the single branch outage forcing a constraint, security of supply is still at risk for the following reasons:

- The configuration of the existing 110kV overhead circuits into Central Park share a common tower on their entry to Central Park. A catastrophic failure on this tower would result in the loss of all three circuits into Central Park.

- The 110kV circuits from Wilton to Central Park are on two separate routes with a double circuit line on one tower route and single circuit on a different tower route. Due to the high demand at Central Park two 110kV circuits are required to be in service at all times in order to supply the required peak demand. An outage on the double circuit line from Wilton affecting both circuits would result in reduced supply capacity to Central Park regardless of whether there is a 110kV bus at Central Park.

- All three 110kV circuits are supplied from the same bus at Wilton GXP. A full outage on the 110kV bus at Wilton would cause a complete loss of supply to Central Park. This has occurred in the past. Transpower has indicated a review is underway to improve the reliability of the Wilton bus, although the only way to guarantee supply reliability would be to physically split the 110kV bus at Wilton.

Option 3 – Provide an alternative supply into Central Park

The previous options mitigate operational risks at Central Park but there will still be residual security of supply risks unless diversity is added to the supply routes. There are two prospective routes for alternative 110kV supply into Central Park as explained below.

Route Option 1: Kaiwharawhara to Central Park GXP

Route option 1 would be to run new 110kV circuits from Kaiwharawhara to Central Park and form a closed ring between Wilton, Kaiwharawhara and Central Park.

Kaiwharawhara is presently an 11kV GXP Point of Supply with two 110/11kV power transformers supplied from Wilton by 110kV overhead circuits. There is presently no 110kV bus at Kaiwharawhara and due to space constraints at this site this option may not be feasible. Additionally the requirements to cable through the Wellington CBD from Kaiwharawhara to Central Park would be of significant cost given required cable size and operating voltage.

Route Option 2: Gracefield to Evans Bay Zone Substation

This option has been considered for at least the past 30 years by both the former NZED and the Capital MED. The Capital MED installed 110kV oil cables between Central Park and the Evan's Bay zone substation in the early 1980s. At present these cables are operated at 33kV and supply the 8 Ira St Substation but are terminated on overhead structures at Evan's Bay. By extending the overhead 110kV circuits from Gracefield GXP up to Camp Bay (Eastbourne) and then installing submarine 110kV cables across the harbour into Evans Bay zone substation a closed ring of 110kV is possible.

Two possible configurations exist – either develop a GXP at Evans Bay to supply the local area or bypass Evans Bay and close the ring between Gracefield and Central Park. Regardless of which configuration was selected, reconfiguration of the existing 33kV supply would be required at Evan's Bay involving the installation of a 33kV switchboard.

Gracefield GXP is supplied from Haywards by double 110kV overhead circuits and supplies Seaview, Korokoro, Gracefield and Wainuiomata zone substations.

Figure 5-16 shows the layout of a possible route from Gracefield to Evans Bay zone substation.

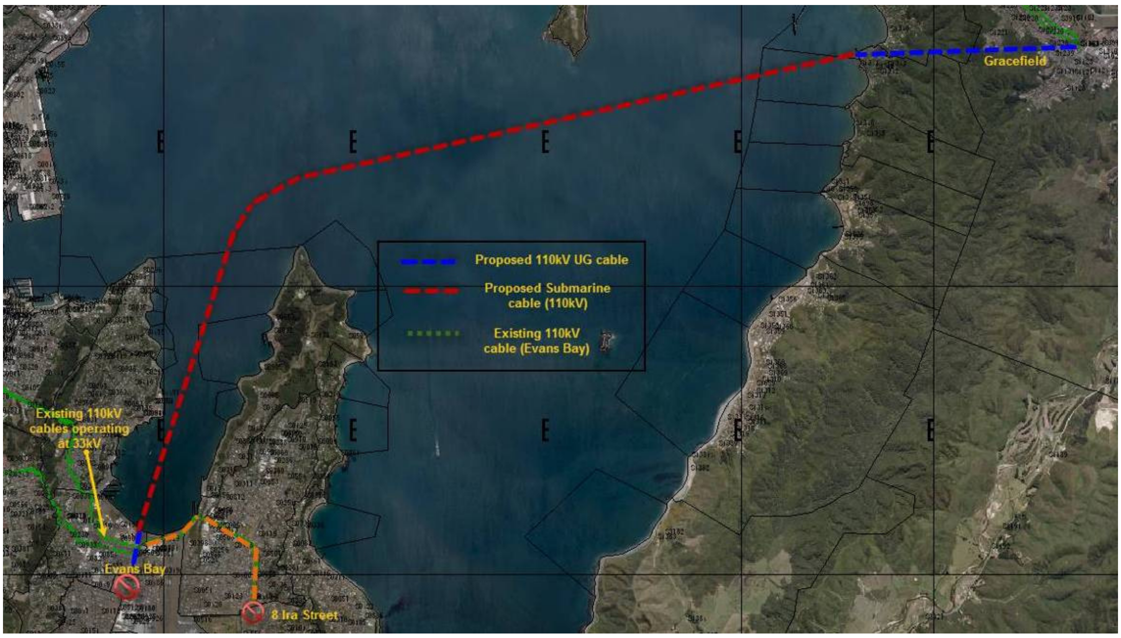

Figure 5-16 Possible Route from Gracefield to Evans Bay Zone Substation

Two significant drawbacks to this option are the capacity constraints on the 110kV circuits between Haywards and Gracefield, which would not provide sufficient capacity to supply the Wellington City area if extended around to Evans Bay and Central Park. Also the age of the existing 110kV cables between Central Park and Evans Bay are now 30 years old and would be around 40 years old by the time such a project was implemented. The system elements which lead to this option being considered are unlikely to be fit for purpose and significant investment may be required.

Options development for Central Park and Wilton are presently being completed by Transpower. Wellington Electricity is working closely with Transpower to ensure the needs of both companies and stakeholders are met. This study work is expected to be completed by mid 2013, and will allow both parties to consider development options for the remainder of the planning period.

5.12.2. Gracefield

Currently there are two transformers at Gracefield which provide 33kV supply to four Wellington Electricity zone substations. There are no capacity and security issues at Gracefield as the peak demand at this GXP is below the supply transformer capacity. The 2012 peak demand at Gracefield was 51.8MVA recorded in month of June.

The protection on the subtransmission circuits from Gracefield were installed in the 1970s. These relays are now at the end of their technical life and are will need to be replaced during the planning period. Wellington Electricity will upgrade all subtransmission circuit differential protection from the Gracefield GXP that it owns (Transpower owns over current and earth fault relays), including upgrading all differential protection schemes to modern numeric relay schemes in 2019. The existing subtransmission protection at Gracefield does not monitor the pilot cables health and any future protection upgrade would include the pilot health monitoring along with differential protection scheme.

5.12.3. Haywards

Currently there are two transformers at Haywards, for 33kV and 11kV supply respectively. The 33kV supply to Trentham can be backed up from the Upper Hutt GXP (via the Maidstone and Trentham zone substations at 11kV) and the 11kV supply points backed up from the Melling GXP and the Trentham zone substation though the Wellington Electricity owned 11kV network.

Transpower has identified the need to replace the existing transformers at Haywards as a policy project in the short term and there are currently discussions underway as to what the optimal replacement configuration will be. Transpower recognises the level of security offered is lower than would be expected at such a site and routine maintenance on these existing assets is difficult due to the configuration. Several options have been discussed with Wellington Electricity and Transpower is now evaluating the following options:

- Replace the existing configuration (1x 11kV and 1x 33kV supply transformer)
- Replace with two supply transformers for each voltage (2x 11kV and 2x 33kV)
- Replace with one supply transformer for each voltage and one interconnecting transformer (1x 11kV, 1x 33kV and 1x 33/11kV transformer)
- Replace with two, three winding transformers to provide both 33kV and 11kV from the 110kV supply

5.12.4. Pauatahanui

The Pauatahanui GXP supplies the Mana and Plimmerton zone substations via a single 33kV overhead circuit connection to each substation. Mana and Plimmerton zone substations are linked at 11kV providing a degree of redundancy should one of the 33kV connections be out of service.

Pauatahanui GXP comprises a conventional arrangement of two parallel 110/33kV transformers rated at 20MVA each. The maximum peak demand on the Pauatahanui GXP in 2012 was 18.9 MVA. This is within the transformer emergency ratings and also cyclic ratings of 22MVA. The load growth in this area is relatively high and the transformer cyclic rating is forecasted to have around 2 MVA of shortfall at the end of the planning period.

In time, the additional load supplied from Pauatahanui will have an impact on the Transpower 110kV system north to Paraparaumu as Transpower have constraints on the overhead circuits. Discussions have been held with Transpower regarding the prospective load increases at Pauatahanui and the wider 110kV system issues.

As per Transpower planning documents, the peak load at Pauatahanui is forecast to exceed the transformers N-1 capacity by approximately 1 MW in 2012, increasing to approximately 8 MW in 2027.

Transpower has indicated in their Annual Planning Report that the 110kV constraint issue needs to be addressed in the medium term. This will allow additional load out of Pauatahanui and also upgrading of the existing 110/33kV transformers.

Wellington Electricity will also consider an upgrade of the subtransmission differential protection from this site within the later part of the planning period.

5.12.5. Takapu Road

The Takapu Road GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 90 MVA each. Maximum demand on the Takapu Road GXP in 2012 was 92.0 MVA. Takapu Road supplies zone substations at Waitangirua, Porirua, Kenepuru, Tawa, Ngauranga and Johnsonville each via double circuit 33kV. These circuits leave the GXP as overhead lines across rural land and become underground lines at the urban boundary.

The Ngauranga 33kV circuits utilise the old Takapu Rd – Khandallah 110kV line operating at 33kV which Transpower owns and maintains. Discussions around the ownership and connection of this line are ongoing as Transpower are open to divesting this asset. By owning the asset Wellington Electricity may derive more benefit when considering options for supply upgrades into the Johnsonville, Grenada and Newlands areas. There are however considerations to be made on the age, condition and location of the line as there is significant under-build on this tower line.

The installed 110/33kV transformer capacity at Takapu Road GXP is 100MVA with a possible N-1 cyclic capacity of 116MVA. This was previously constrained by a protection limitation however work has been undertaken to remove this and the transformer N-1 cyclic ratings has been increased from 92MVA to 107MVA.

Transpower has notified that they will be replacing the Takapu Road GXP 33kV outdoor switchgear with indoor switchgear in 2015. During this outdoor to indoor conversion, a full review and upgrade of the substation protection will occur. The protection limits on Takapu Road GXP transformers will be further raised to provide full transformer N-1 cyclic ratings of 116MVA, which will result in no forecast capacity issues at Takapu Road GXP until 2030.

At the time of this upgrade, Wellington Electricity will upgrade all subtransmission circuit protection from the Takapu Rd GXP that it owns, including upgrading all differential protection schemes.

5.12.6. Upper Hutt

The Upper Hutt GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 37 MVA each, supplying 33kV bus that feeds to zone substation at Brown Owl and Maidstone by underground 33kV fluid filled cables. Maximum demand on the Upper GXP in 2012 was 31.0 MVA, which is within GXP firm capacity. The existing Solkor differential protection on the Wellington Electricity subtransmission circuits from Upper Hutt has been reliable but this protection does not have pilot wire monitoring. This presents a risk that if the pilot has become damaged the protection may not operate as intended.

Transpower has notified that it will be replacing the Upper Hutt GXP 33kV outdoor switchgear with indoor switchgear around 2015. During this outdoor to indoor conversion a full review and upgrade of the substation protection will occur. In addition, at the time of this upgrade, Wellington Electricity will upgrade all subtransmission circuit protection from the Upper Hutt that it owns, including upgrading all differential protection schemes.

5.12.7. Wilton

Wilton GXP comprises two 220/33kV transformers operating in parallel, supplying a 33kV bus that feeds to zone substations at Karori, Moore Street, and Waikowhai Street. These transformers are nominally rated at 100 MVA each and the maximum demand in 2012 was 52.0 MVA.

Meridian Energy has recently obtained resource consent for the Mill Creek wind farm in the Ohariu Valley area which has a capacity of around 60 MW. If there were to be any connection from the wind farm to the Wellington network, or shared connection points, it would be at 33kV or higher. The proposed wind farm at Mill Creek would be more likely to be connected at Wilton 33kV Bus, which would require an additional two 33kV circuit breakers. Transpower has notified that it will be replacing the Wilton GXP 33kV outdoor switchgear with indoor switchgear around 2014 and would provide additional two bays for connection of the Mill Creek wind farm.

At the time of this upgrade, Wellington Electricity will upgrade all subtransmission circuit protection that it owns (except for Moore Street which has already been upgraded) from the Wilton GXP, including upgrading all differential protection schemes.

5.12.8. Wellington 220kV-110kV interconnection capacity

Presently, the 110kV and 220kV networks in Wellington are interconnected at Haywards and Wilton, and Transpower have identified that within the planning period another interconnecting bank will be required in the region, especially following the commissioning of the Pole 3 DC link.

As an alternative to this, an opportunity exists to install a subtransmission link on the Wellington Electricity network at 33kV to enable the transfer of load from the 110kV system (ex-Central Park) to the 220kV system (ex-Wilton) as required. Transpower and Wellington Electricity are currently working through this option to determine costs and feasibility. A benefit to Wellington Electricity is also the ability to move load away from Central Park at times when the incoming supply is constrained (N-1 events) and the SPS is armed, thus reducing the load at risk should a second contingent event occur.

If this option were to proceed, greater understanding of the trade-off of investing in the Wellington Electricity network as an alternative to an investment in the Transpower system would need to be explored.

If the proposal of constructing a new zone substation in Bond Street proceeds, then interlinking Bond Street (potentially supplied from Central Park) and Moore Street zone substations (or the Wilton GXP) at 33kV level could potentially be the best option although the space constraints for installing a 33kV switchboard at Moore Street will need to be addressed. This idea will be further developed during 2013 and updated in the next AMP.

The subtransmission link concept is estimated to be in the order of $8 to $12 million. This is not included in current expenditure forecasts due to the uncertainty of the work.

5.13. Zone Substations – Constraints and Development Plans

Figure 5-17 provides installed sub-transmission capacities and forecast demands for the beginning and end of the forecast period. This table is intended to provide an indication of loadings on the sub-transmission system.

Zone Substation	Transformer Cyclic Capacity (MVA)	Single Incoming Circuit Capacity (MVA)	Peak Season	Forecast Demand (MVA)	
				2013	2022
8 Ira Street	24	21/15	Winter	17.3	20.0
Brown Owl	23	19/13	Winter	15.7	17.6
Evans Bay	24	19/15	Winter	16.1	18.7
Frederick Street	36	30/22	Winter	29.7	34.9
Gracefield	23	21/17	Winter	12.8	14.5
Hataitai	23	22/13	Winter	17.8	19.8
Johnsonville	23	21/14	Winter	15.5	18.6
Karori	24	21/11	Winter	17.5	19.9
Kenepuru	23	19/14	Winter	11.4	14.6
Korokoro	23	22.5/16.5	Winter	18.5	20.6
Maidstone	22	18/10	Winter	15.2	17.2
Mana-Plmtn	16	27/23	Winter	19.2	21.9
Moore Street	36	36/31	Summer	26.1	32.5
Naenae	23	19/14	Winter	15.7	17.8
Nairn Street	30	25	Summer	19.8	23.0
Ngauranga	12	20/14	Winter	13.0	14.6
Palm Grove	24	21/17	Winter	27.9	31.7
Petone	20	19/13	Winter	N/A	N/A
Porirua	20	22/14	Winter	17.9	20.3
Seaview	22	21/13	Winter	15.0	16.9
Tawa	16	21/14	Winter	14.9	19.6
The Terrace	36	35/30	Winter	30.2	34.8
Trentham	23	20/14	Winter	15.1	17.1
University	24	24/18	Winter	26.3	30.8
Waikowhai	19.2	22/15	Winter	16.3	17.8
Wainuiomata	23	22/12	Winter	17.2	19.3
Waitangirua	16	22/16	Winter	15.0	16.5
Waterloo	23	21/13	Winter	18.3	20.7

Figure 5-17 Zone Substation Capacities and Loadings

The majority of zone substation assets have sufficient capacity available throughout the planning period. There are seven zone substations where the assets have capacity constraints at present, or constraints arising within the planning period. These zone substations are:

- Frederick Street
- Johnsonville
- Mana – Plimmerton
- Palm Grove
- Trentham
- University
- Wainuiomata

The capacity constraints are addressed in the following sections with a range of options presented.

5.13.1. Additional 11kV Capacity in CBD

System demand is presently very high in the central Wellington area at both subtransmission and distribution level as a result of new developments and load growth over the past decade. This is largely being accommodated by existing capacity from Frederick Street, The Terrace, Moore Street and Kaiwharawhara substations. The 11kV distribution system is experiencing high loadings and there are limited options for increasing the 11kV capacity from the existing substations, both physically in terms of site constraints, but also upstream subtransmission constraints. From the load forecasts it can be seen that there is a requirement to have significant additional 11kV capacity in the CBD by around 2015 to address new and historic load growth.

Currently there are two detailed options under investigation by Wellington Electricity.

Option 1 - Construction of a new GXP in the CBD with an 11kV point of supply

One of the high level options Transpower has proposed to address the loading and diversity risks at Central Park is to construct another 110/33kV GXP in the Wellington CBD. Wellington Electricity has proposed to Transpower that if this option were selected it would be beneficial to install two three winding 110/33/11kV transformers instead of a 110/33kV transformer. Creating an 11kV point of supply with an 11kV switchboard at the GXP will provide additional 11kV capacity in CBD of potentially up to 30 MVA. If this proposal proceeds, it will off load the Frederick Street, The Terrace, Palm Grove and Moore Street zone substations at 11kV which are currently heavily loaded, as well as providing an additional GXP for 33kV supply to the CBD zone substations at Frederick Street and The Terrace. High level planning and analysis is in progress with Transpower.

Installing three winding transformers at the proposed GXP would not only provide new capacity at 11kV but also at 33kV subtransmission level as well. This will allow reconfiguration of supply to the CBD zone substations to address constraints at subtransmission level, as well as reducing overall loading. This option would provide a solution to the present and forecast capacity issues on the Wellington Electricity network in the CBD until well beyond the planning period.

Option 2 – Build a new zone substation in the CBD

Wellington Electricity owns a bare land site in Bond Street. If a new GXP proposal with an 11kV point of supply option does not go ahead, Wellington Electricity would utilise this property to construct a 33/11kV zone substation with an installed capacity of 2x 30MVA. Figure 5-18 shows land owned by Wellington Electricity in Bond Street which could be used for a new zone substation.

The subtransmission supply to the proposed Bond Street substation would be provided from Central Park GXP through high capacity underground 33kV circuits as the route is through the CBD. An alternative option would be to supply the substation from the Wilton GXP, however the geographical location of Wilton, would require the sub transmission cables to be three times the length required from Central Park. The recommended option for subtransmission supply to the new zone substation in Bond Street would be from Central Park. This would however compound the loading and security issues at the Central Park GXP identified earlier in this section, and a firm plan for resolving these would need to be agreed between Wellington Electricity and Transpower before planning for the substation commenced.

In addition, a Bond Street substation could be interlinked with the Moore Street substation at 33kV by installing double 33kV underground circuits between the sites. This would provide security of supply not only to Bond Street and Moore Street substations but also to interconnecting substations supplied from Central Park should there be outage on Central Park GXP.

Figure 5-18 Land Owned by Wellington Electricity for Possible Substation in Bond Street

Figure 5-19 provides a high level cost estimate and time periods for this option of a Bond Street substation.

Option Description	Cost	Year investment is required	Duration of Solution
1. New 2X30MVA, 33/11kV zone substation in Bond Street (eight 11kV feeders) 2. Two 33kV Circuits from Central Park to Bond Street substation **Ref 15-001**	$15 million $5 million	2015	Beyond 2030
3. Existing 11kV distribution network re-configuration around new Bond Street substation **Ref 16-003**	$2 - $3 million	2016	Beyond 2030
Total estimated cost	**$22-23** million		

Figure 5-19 Cost Estimate for Possible Substation in Bond Street

5.13.2. Frederick Street Subtransmission Replacement

Frederick Street zone substation is presently one of the most highly loaded substations on the Wellington network. Maximum demand is approximately 99% of N-1 sub transmission capacity and there is limited capacity in the 11kV interconnections with adjacent substations to allow offloading at peak times, which is further limited due to high demand on neighbouring feeders. The 2012 peak demand at Frederick Street was 29.2MVA. The demand is expected to increase over the years and by the end of 2023, the Frederick Street subtransmission N-1capacity would have a shortfall of 5.0 MVA at current growth rates.

The cables between Central Park and Frederick Street were installed in 1979 and are now 34 years old. They are three core 33kV PIAS (paper insulated aluminium sheath) gas filled cables with an underground circuit length of 1.5km. These cables are generally reliable and have not experienced modes of failure similar to gas cables installed on the network in other locations. The Stage of Life analysis has given an overall score of 6.0 for these cables which ranks as number four on the Stage of Life prioritised list due to their high utilisation. The existing subtransmission capacity does not match the Frederick Street zone transformer firm capacity and has shortfall of 5MVA between the transformer and cable capacity.

To address this capacity constraint, the best option identified is to replace the existing Frederick Street gas filled 33kV cables with new high capacity 33kV XLPE cables. The new cables will not only provide increased capacity but also provide a higher level resilience to a catastrophic event compared to existing gas filled cables. Another advantage of replacing the existing gas filled cables with XLPE would be the ease of repair and lower overall cost of ownership due to the lower maintenance requirements. The new XLPE cables would be preferred to be installed between new GXP in the CBD and Frederick Street zone substation.

Figure 5-20 provides a high level cost estimate and timing for installing high capacity XLPE 33kV cables. This timing also allows for a possible new CBD GXP which could mean supply to Frederick Street can be moved off the Central Park GXP.

Project Description	Cost	Year investment is required	Duration of Solution
Installation of double XLPE 33kV circuit between Central Park/new GXP and Frederick Street **Ref 18-001**	\$7 - \$8.5 million	2018-19	Beyond 2030

Figure 5-20 Cost Estimate for new Frederick Street Subtransmission Circuits

5.13.3. Johnsonville

Johnsonville has experienced high load growth over the past decade as a result of residential development, which is ongoing, and has a current winter peak load demand of 22.6 MVA. Johnsonville zone substation is supplied by two 33kV circuits from the Takapu Road GXP, which start as an overhead line through rural land and then change to underground cables for the last 5 kilometres into Johnsonville. The subtransmission N-1 capacity shortfall was in the order of 2 to 3MVA at peak load time. A project to install new 11kV feeder interconnections with Ngauranga has been completed which has shifted around 4 to 5MVA of peak load from Johnsonville to the Ngauranga zone substation. This has reduced the loading on Johnsonville subtransmission and created around 1 to 2 MVA of spare capacity at this site. This has resolved the N-1 security issues until around 2016-17 at forecast growth levels. This feeder between Ngauranga and Johnsonville will provide a useful interconnection between substations for its entire service life.

The northeast side of Johnsonville (Grenada Village) is experiencing load growth with an increased number of subdivisions in Grenada Village underway or being in the consenting process. This load growth along with the previous high levels of growth in Churton Park (to the north of Johnsonville) has led to a present capacity constraint in this area, which will continue to be an issue as future developments are completed. There are limited options for increasing 11kV capacity and security into these areas from Johnsonville.

Different options have been analysed and load flow simulation indicates it is not possible to run new 11kV capacity from the Tawa zone substation (to the north of Johnsonville) due to the geographic location and also its high utilisation factor. Johnsonville substation is already highly utilised and within five years will again be operating outside its security criteria. The best option, which is currently being developed, is the construction of a new zone substation to the north or north-east of Johnsonville by 2017, to supply the existing high loads and to allow for high load growth in this area. Land has been purchased in Grenada in 2012 to allow for this construction when required. The site will be designated and easements created for connecting to the existing networks in the area. The new substation would not only supply load growth in and around Grenada area, but also off load Johnsonville feeders 2 and 3 and Tawa Feeders 3 and 11.

The subtransmission supply to the new zone substation is proposed to be from the existing Takapu Road - Ngauranga overhead 33kV circuits which pass near this location. Emphasis will be on getting the zone substation site near to these overhead sub transmission circuits. These circuits are owned by Transpower, and Wellington Electricity may be required to take ownership of these to allow a connection from the lines. A 33kV switchboard would be required at the new substation to allow adequate protection and segregation of circuits continuing on to Ngauranga.

Figure 5-21 provides a high level cost estimate and time periods for the new zone substation.

Project Description	Cost	Year investment is required	Duration of Solution
1. Construction of new 20MVA, 33/11kV Zone substation in Grenada **Ref 17-005**	$15 million	2017-18	Beyond 2030
Total estimated cost	**$15** million		

Figure 5-21 Cost Estimate for Possible Substation for Grenada

5.13.4. Mana-Plimmerton

5.11.4.1 Zone Transformer Constraint

Load at the combined zone substations of Mana and Plimmerton can presently exceed the N-1 rating of the zone transformers at peak times. Back feed connections from neighbouring substations allow N-1 operation at present, but this capacity is being eroded over time. The Mana and Plimmerton zone substations have an 11kV tie cable between the two 11kV buses which is operated normally closed. During an outage on either of the zone transformers or one of the sub transmission circuits, the load is transferred by the existing 11kV tie cable and also at 11kV feeder levels as required. It has been known that at peak times the tie cable has tripped out of service on overload in the event of a subtransmission fault, although this is rare (one event in every five years or more).

The existing transformers (ONAF cooling) at Mana and Plimmerton zone substations have cyclic ratings of 16 MVA each with 16.8MVA as the emergency two hour rating. The cyclic ratings of the existing transformers could be increased to around 20MVA by installing oil pumps and converting them to oil forced and air forced (OFAF) cooling transformers. The combined coincident peak of Mana-Plimmerton in 2012 was 18.9 MVA. The individual peak demand of Mana and Plimmerton in 2012 (winter) was 13.1MVA and 6.9 MVA respectively.

Work is under way to decommission the Petone zone substation due to very low loadings and poor asset condition. An option would be to shift one of the Petone zone transformers (rated at 20MVA) to the Plimmerton zone substation following the decommissioning at Petone. Due to space constraints at the Mana zone substation a second transformer cannot be accommodated, however a higher rated unit could replace the existing transformer. By either upgrading to oil forced cooling, or relocating a Petone transformer to Mana and Plimmerton, firm capacity of 20MVA will be provided at these zone substations.

5.11.4.2 Mana-Plimmerton 11kV Tie Cable

The 11kV tie cable between Mana and Plimmerton has a capacity of 7.60MVA. The peak load of Mana zone substation is around 13.1MVA. Should the 33kV circuit supplying Mana zone transformer be out of service, the Mana peak load cannot be supplied from Plimmerton through the existing 11kV tie cable alone.

Figure 5-22 shows the layout of Mana and Plimmerton zone substations.

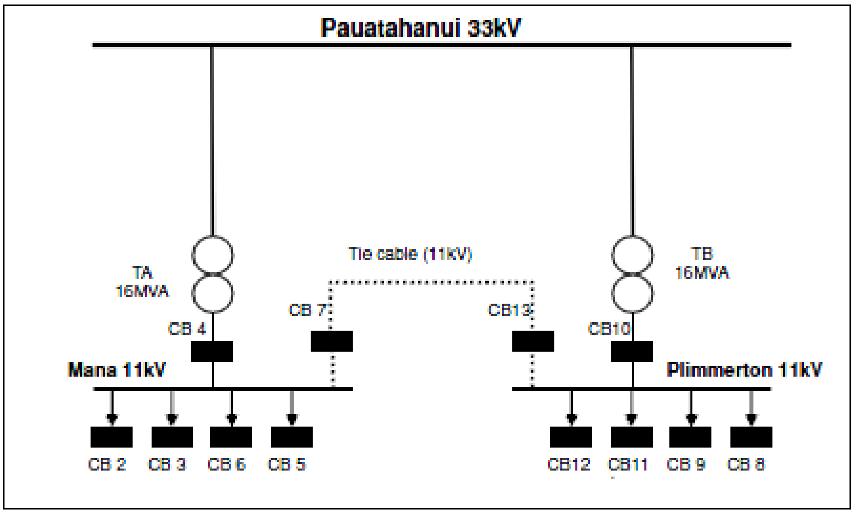

Figure 5-22 Mana-Plimmerton Connection Layout

During an outage under the present conditions, two things may occur – the loads are operationally managed through peaks or the load is transferred away by manual switching of the 11kV network. This results in not having true N-1 security at these sites.

There are two options considered to eliminate the constraints on the 11kV tie cable between Mana and Plimmerton.

Option 1: Install a higher capacity Tie Cable

This is a high cost option and requires a high capacity cable to be installed along State Highway 1 between the two sites.

There is presently one 11kV tie cable linking the two 11kV buses. This option would involve installing another high capacity 11kV cable as a second tie cable. However, installing high capacity 11kV cables will only supply the forecast Mana peak load up to around 2013 (the year construction would be undertaken), and, if operated as the only tie circuit (i.e. the existing tie cables are not used), could not supply the entire Plimmerton demand if the 33kV subtransmission supply is out of service. The existing 11kV tie cables could not be operated in parallel with the new cables because of load sharing imbalances as a result of the impedance differences.

To utilise both 11kV tie cables (existing and the proposed new cable), a reconfiguration of 11kV switchgear and the addition of a bus coupler would be required at the Plimmerton zone substation (as shown in Figure 5-23). The addition of a bus coupler is not possible at Mana zone substation due to space constraints. The proposed arrangement would split up the feeders and a special protection scheme will provide N-1 security of supply until around 2018 should the 33kV circuit supplying Plimmerton be out of service.

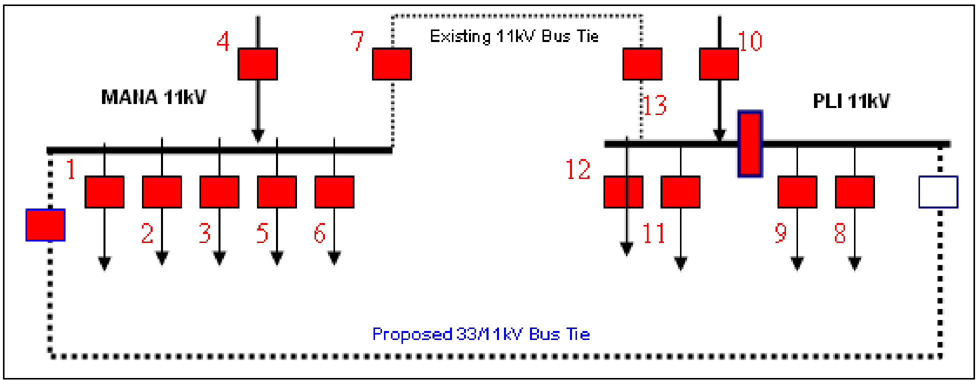

Figure 5-23 Proposed Option 1 Layout for Mana-Plimmerton

Figure 5-24 provides a high level cost estimate and time periods for the option of running a new cable between Mana and Plimmerton zone substations. High capacity single core cables have been used as the basis for the cost estimate to give the best possible rating from the new circuit. A lower cost, lower capacity three core cable could be used instead.

Project Description	Cost	Year investment is required	Duration of Solution
Install new single core, 630mm^2, Al, cables between Mana and Plimmerton zone substations	$2.7 million	2013	2017-18
Two new 11kV circuit breakers and one bus coupler at Mana and Plimmerton	$135,000	2013	2017-18
Special protection scheme	$75,000	2013	2017-18
Total Project cost (Option 1)	**$2.91** million		

Figure 5-24 Cost Estimate for Option 1 Layout for Mana-Plimmerton

This option is not recommended because of the cost, poor relative benefits, and the likelihood that space constraints at Mana and Plimmerton would be an issue.

Option 2: Implementation of Special Protection Scheme

As an alternative to the installation of a new tie cable and switchgear reconfiguration at the Plimmerton zone substation, a special protection scheme (SPS) could be utilised to avoid overloading and allow for network reconfiguration under fault conditions.

A SPS with intertrip and close functions could be utilised to fully off load Mana Feeder 5 and 6 onto the Porirua zone substation following an outage on either the 33kV circuit or zone transformer at Mana to prevent the overloading of the 11kV tie cable. Implementing a SPS would manage the load through the existing 11kV tie cable. The residual loading would remain within the rating of the cable until around 2018 at current forecast growth rates.

Mana Feeders 5 and 6 have full backup from Porirua Feeder 2 and Titahi Bay Feeder 3 respectively. Implementing the SPS will ensure full backup capacity is available to Mana Feeders 5 and 6 from Porirua substation until 2018. Figure 5-25 provides the overview of the proposed special protection scheme at Mana and Plimmerton.

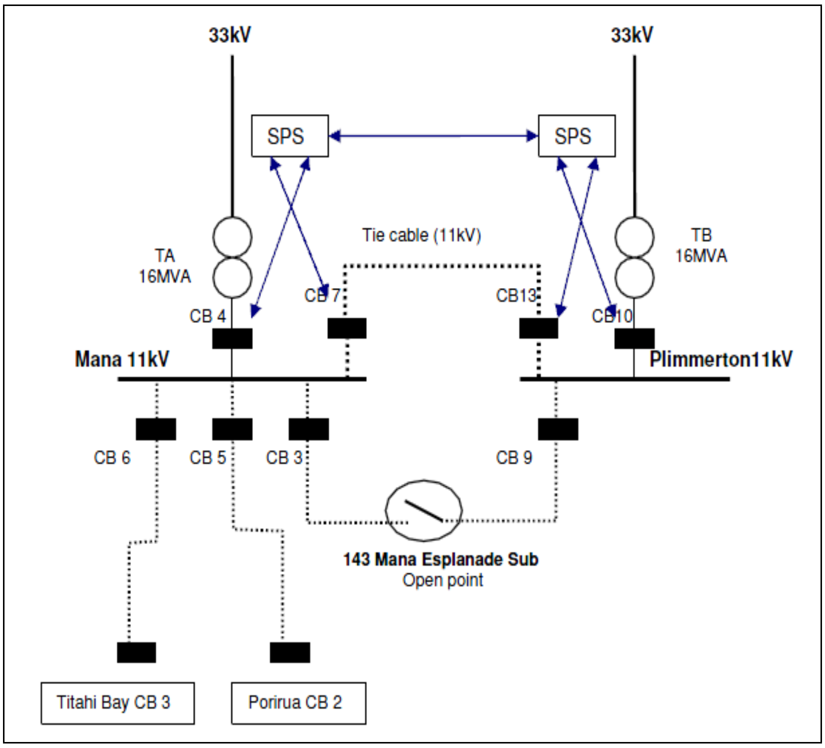

Figure 5-25: Special protection scheme logic at Mana and Plimmerton

As part of the SPS, it is also recommended that a remote operated switch be installed at the 143 Mana Esplanade distribution substation to allow load transfer at 11kV feeder level between Mana and Plimmerton 11kV buses.

Figure 5-26 provides a high level cost estimate and time periods for the SPS implementation.

Project Description	Cost	Year investment is required	Duration of Solution
SPS installed at Mana and Plimmerton zone substations and converting switchgear at 143 Mana Esplanade substation to be remote operated Ref: 14-006	$250,000	2014	2017-18

Figure 5-26 Cost Estimate for Option 2 SPS for Mana-Plimmerton

The feasibility study to confirm the possibly of SPS implementation at Mana and Plimmerton is underway and will investigate the communications part of this scheme between two sites. The feasibility study will be completed during 2013 and, depending on the outcome of the study, the physical work could be completed in 2014.

5.13.5. New Zone Substation in Whitby/Pauatahanui Area

There is both high system demand and high load growth in the Whitby and Pauatahanui area due to large numbers of recent subdivisions as well as subdivisions currently in the consenting process. Due to the geographical location of the load centres in Whitby, it is difficult to install new 11kV feeders from the nearest zone substations (Waitangirua and Mana – which is also highly loaded). The best long term option to address this issue is the construction of new 2x 20-30MVA zone substation in the Whitby area. This would reduce loading on Mana, Waitangirua and Porirua zone substations and provide capacity for any future load growth. Subtransmission to the new zone substation would be taken from the Pauatahanui GXP. Figure 5-27 shows the preferred site location for the new zone substation and figure 5-28 provides the estimated cost for new zone substation in Grenada Village.

Figure 5-27 Preferred Site for Possible Substation in Whitby Area

Project Description	Cost	Year investment is required	Duration of Solution
1. Land investigation and land purchase in Whitby for new zone substation **Ref 17-004**	\$1.0 million	2017	Beyond 2030
2. Construction of new 20-30 MVA zone substation in Whitby area **Ref 20-002**	\$15 million	2020-22	Beyond 2030
Total estimated cost	**\$16** million		

Figure 5-28 Cost Estimate for Possible Substation in Whitby Area

5.13.6. Palm Grove

The Palm Grove subtransmission N-1 capacity does not match the zone substation transformer firm capacity and has a shortfall of 6.0 MVA. The current peak load at Palm Grove zone substation exceeds the subtransmission N-1 capacity and also zone substation firm capacity, as is shown in Figure 5-29. Peak demand at Palm Grove in 2012 (June) was 27.50 MVA. The load duration curve shows the load exceeds the N-1 rating for 2.9% of the time which indicates non-compliance with the security criteria requirement of N-1 availability for 98% of the time. Loading on this site is forecast to increase over time further increasing this non-compliance, and the types of load (Wellington Hospital and the Newtown commercial area) supplied are sensitive to outages.

Load forecast analysis shows that loading in the CBD area is very high, and is continuing to grow as a result of step change load increases. Following the recent transfer of load from Frederick Street to Nairn Street, all CBD zone substations (Frederick Street, The Terrace, Nairn Street, Moore Street and Palm Grove) are roughly evenly loaded. As the load continues to grow, the CBD zone substations will be approaching their firm capacity at about same time. As mentioned earlier, capacity in the CBD is required to have an additional 11kV by around 2015. Assuming this is achieved, it will allow shifting some load from Palm Grove on to the CBD new zone substation. The sub transmission constraint at Palm Grove, which by this time will have a 6 MVA N-1 capacity shortfall, still remains to be addressed.

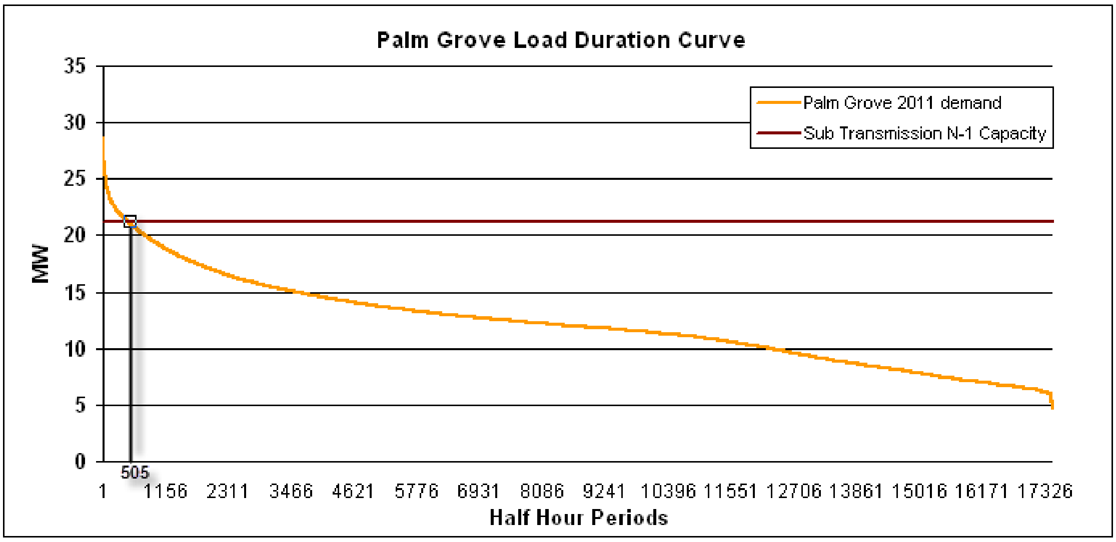

Figure 5-29 Load Duration Curve for Palm Grove Substation

Two options exist to improve the rating of the Palm Grove subtransmission circuit:

1. Install a new single 33kV XLPE circuit and run the two existing 33kV circuits in a duplex configuration. This is a lower cost and utilises the existing cables but the existing cables are end of their serviceable life and will require installation of second XLPE circuit in near future.

2. Replace both existing circuits with new high capacity XLPE subtransmission cables between Central Park and Palm Grove as shown in figure 5.30. This is preferred option as it would cost less to replace both circuits at the same time than installing two circuits individually. This will provide a higher level of supply resilience to Palm Grove than the existing gas filled cables.

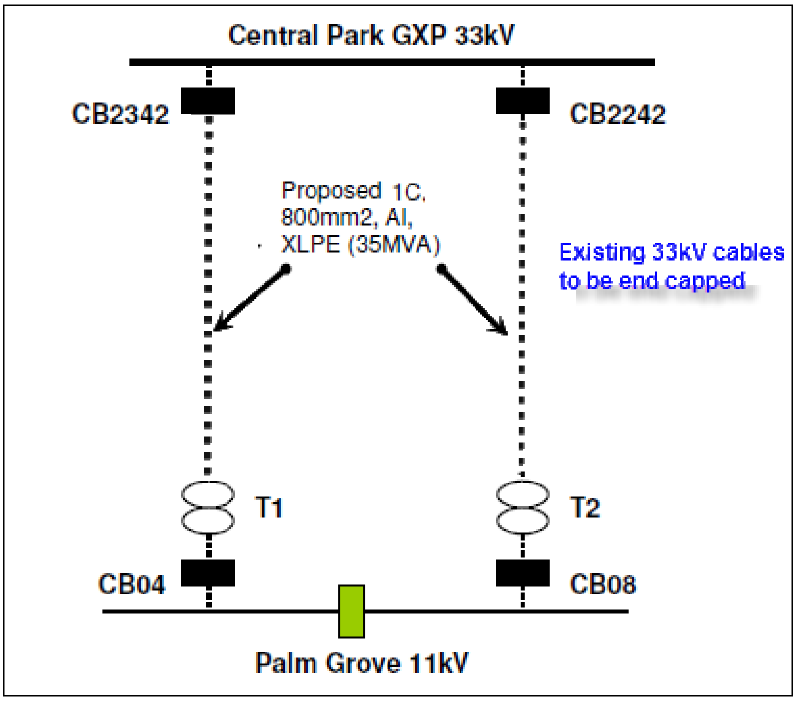

Figure 5-30 Proposed Configuration for Palm Grove Subtransmission Circuits

Option 2, although more expensive initially than option 1, provides a solution with more capacity than the N-1 zone transformer capacity. It also provides an opportunity to upgrade the zone transformer to 30MVA or greater in future, to match the loading in this area and utilise the full capacity of the zone substation switchboard. The XLPE cables will have higher resilience to a catastrophic event when compared to the existing gas filled cables. The whole of life NPV calculation indicates that option 2 has the least overall cost compared to installing only a single circuit and operating the existing circuit in duplex configuration then returning to replace the remaining gas cables in around 10 years time.

Figure 5-31 provides a high level cost estimate for the preferred subtransmission circuit improvement at Palm Grove.

Project Description	Cost	Year investment is required	Duration of Solution
Installation of double circuit XLPE 33kV cables between Central Park and Palm Grove **Ref 13-002**	\$7 - \$9 million	2013-14	Beyond 2030

Figure 5-31 Cost Estimate for Option 2 Subtransmission Circuit

There is another identified constraint at Palm Grove with the 11kV distribution network not having any open points to allow paralleling between the zone 1 and zone 2 ring networks (i.e. each side of the 11kV bus). Palm Grove zone substation is normally operated with a split 11kV bus configuration and there is no option available for shifting load between T1 and T2 buses at distribution network levels. This presents a risk during an outage on either of bus sections at Palm Grove. Currently there is adequate capacity to offload one side of each bus onto adjacent zone substations at 11kV. Should the respective sides of the bus not be available, a study will be undertaken to find options for linking the two sides of the bus together at 11kV in the distribution network.

In the short term a network load flow study will be undertaken to identify possible locations to install open points between two parts of the Palm Grove zone substation distribution networks to offer better operational flexibility at distribution level. Figure 5-32 provides the estimated cost and time frames for creating the interconnectivity between the Palm Grove zone 1 and zone 2 distribution networks.

Project Description	Cost	Year investment is required	Duration of Solution
Install interconnectivity between two Palm Grove distribution network zones **Ref 16-001**	$500,000	2016	Beyond 2030

Figure 5-32 Cost Estimate for interconnectivity b/w Palm Grove Z1 and Z2 distribution network

5.13.7. Trentham Subtransmission Protection Upgrade

Trentham zone substation is supplied from Haywards GXP at 33kV by two subtransmission circuits composed of overhead and underground 33kV sections. The peak demand at Trentham in 2012 was 14.9 MVA recorded in the month of June and is within the ratings of the substation. The subtransmission circuits have Solkor protection between the 33kV circuit breaker at Haywards and the 11kV incomer circuits at Trentham zone substation, which operate across a pilot wire between the sites. The existing Solkor protection does not have the option of monitoring the pilots which presents a high risk to the subtransmission protection should a fault develop on the pilot wires. The subtransmission protection experienced this mode of failure during the September 2012 storm.

The existing Trentham subtransmission protection is intended to be upgraded with new differential relays, which will provide the monitoring of the pilot circuits and would mitigate the identified risks.

Figure 5-33 provides a high level cost estimate and time periods for replacing the Solkor protection with new differential relays.

Project Description	Cost	Year investment is required	Duration of Solution
Protection upgrade at Trentham subtransmission circuits **Ref 14-003**	$350,000 - $400,000	2014	Beyond 2030

Figure 5-33 Cost Estimate for Trentham Subtransmission protection upgrade

5.13.8. University Subtransmission Reinforcement

The peak demand at University zone substation is above its subtransmission capacity and it would have a capacity shortfall of 5MVA by 2020. The University zone transformers have an emergency rating of 28MVA, which is higher than its subtransmission N-1 capacity.

The University subtransmission circuits have a section of XLPE and a section of gas filled cables with a transition gas to XLPE joint on both circuits. The gas filled cables are three core copper PIAS (paper insulated aluminium sheath), gas insulated cables with a length of 600m and were installed in 1987 (believed to be of old stock cable at that time as gas was not widely used at that time). The XLPE cables are single core 400mm^2 aluminium and were installed in 2006 to replace an older section of gas filled cable with a length of 2.25km. The XLPE cables are new and reliable but the gas filled cables are 26 years old and are now undersized as well as presenting a risk to reliability longer term.

The Stage of Life analysis has given an overall score of 5.4 for the University subtransmission cables and is ranked as number two on the Stage of Life prioritised list due to their high utilisation. The existing subtransmission capacity does not match the University zone transformer N-1 capacity and has shortfall of 4MVA under N-1 conditions. This risk to reliability is presently managed through 11kV network capacity.

Two options are considered for addressing this risk:

1. Installing a single new XLPE cable between the existing XLPE transition joints in Adams Tce to University zone substation as a complete XLPE cable circuit, and paralleling the two existing gas cables to connect to the single XLPE supply from Central Park GXP at this location. This would be lower cost than an outright replacement of the cables, however the complexity of duplexing gas cables to a single XLPE cable may introduce cost and reliability issues.

2. The section option would be to replace the existing section of gas filled subtransmission cables with high capacity 33kV XLPE cables. The new cables will provide increased capacity with an option of upgrading University zone substation to a firm 30MVA substation, as well as providing a high level of resilience to a catastrophic event compared to existing gas filled cables. Another advantage of replacing the existing gas filled cables with XLPE would be the ease of repair and lower overall cost of ownership due to the lower maintenance requirements. This will allow removal of the existing transition joint on the corner of Aro Street and Adams Terrace with a normal XLPE straight joint. This is the preferred option as it addresses a number of the risks, without introducing any new risks.

Figure 5-34 provides a high level cost estimate and time periods for replacing the gas filled University subtransmission cables

Project Description	Cost	Year investment is required	Duration of Solution
Replace the gas filled section of University subtransmission circuits with double circuit XLPE 33kV cables **Ref 17-002**	$3.5 million	2017-18	Beyond 2030

Figure 5-34 Cost Estimate for University Subtransmission reinforcement

5.13.9. Wainuiomata

Wainuiomata zone substation had a winter peak demand in 2012 of 17.0 MVA with a typical residential load profile. Wainuiomata zone substation is supplied from the Gracefield GXP by two 33kV overhead lines with a cable section at the GXP end. There are almost no 11kV back feed supply options available to this because of geographic constraints (Wainuiomata is in a separate valley to the rest of the Hutt Valley, divided by a large hill) with only one limited back feed at 11kV. This is generally not a problem as there is N-1 subtransmission supply, and only a GXP outage, an dual circuit subtransmission outage event (e.g. should there be a bushfire on the Wainuiomata hill) or an 11kV bus fault would cause an entire outage, all of which are considered to be very rare and outside the type of events covered by Wellington Electricity's planning criteria.

Whilst an N-2 event is outside the normal Wellington Electricity security criteria for planning network developments, the lack of 11kV back feed makes this a situation worthy of further consideration. The majority of zone substations on the network have a certain level of backfeed possible through the 11kV network, which is typical of an interconnected urban network, whilst not necessarily planned that way.

In the short term, a network planning study will be undertaken to quantify the risk and the economics of such an investment. This would need to consider the cost against the risk of a total loss of supply. This is an area where consumer consultation is required to determine whether they are willing to pay more for a higher level of security. This is a price-quality trade-off which Wellington Electricity cannot make on their behalf. A contingency plan will be developed to deploy mobile generation and to manage rolling outages to reduce the impact of this risk in the mean time.

Two network options exist to improve the security of supply to the Wainuiomata 11kV network.

1. Construction of 11kV overhead lines or under built 11kV on the 33kV lines built over the hilly terrain to improve the 11kV connectivity

2. Utilising a water services tunnel between Wainuiomata and Gracefield by installing cable to provide the interconnectivity at 11kV level (or add resilience to the 33kV supply).

The other issues identified with the Wainuiomata zone substation are related to a mismatch of the subtransmission ratings.

The 33kV 'Wainuiomata A' line is de rated due to a small section of 33kV underground cable (3C, 300mm^2, Al, XLPE) on 33kV circuit 'A' which has a lower rating that the overhead line. A project is included in the 10 year expenditure plan to increase the rating of this circuit by installing a cable to match the existing overhead 33kV line ratings and zone transformers emergency ratings.

The initial section of underground 33kV cables (50m) at the Gracefield GXP are also constrained due to their small size (3C, 240mm^2, Al, PILC) and ideally require an upgrade to match them with overhead subtransmission ratings and zone transformer N-1 capacity. The subtransmission cables have a rating of 21.0MVA which creates an N-1 shortfall of 3.20MVA when compared to the zone transformer N-1 capacity (24.20MVA). These cables will be further constrained by 2021 when the peak load at Wainuiomata will be equal to the rating of the subtransmission cables.

A further constraint is with the 11kV incomer cables, which have a rating of 12.5 MVA but can be run up to 16 MVA as an emergency rating (two hours). The 11kV incomer cables will be constrained in the medium term (around 2015) and an upgrade will be required to match the other component ratings. The incomer capacity would be doubled by replacing the existing incomer cables by two per phase XLPE cables (1x1C, 630mm^2, Al, XLPE, 11kV) but it is not practical to add an existing cable to each of the existing circuits due to the different construction and capacities of the cables.

Figure 5-35 shows the Wainuiomata zone substation layout and highlighting existing constraints.

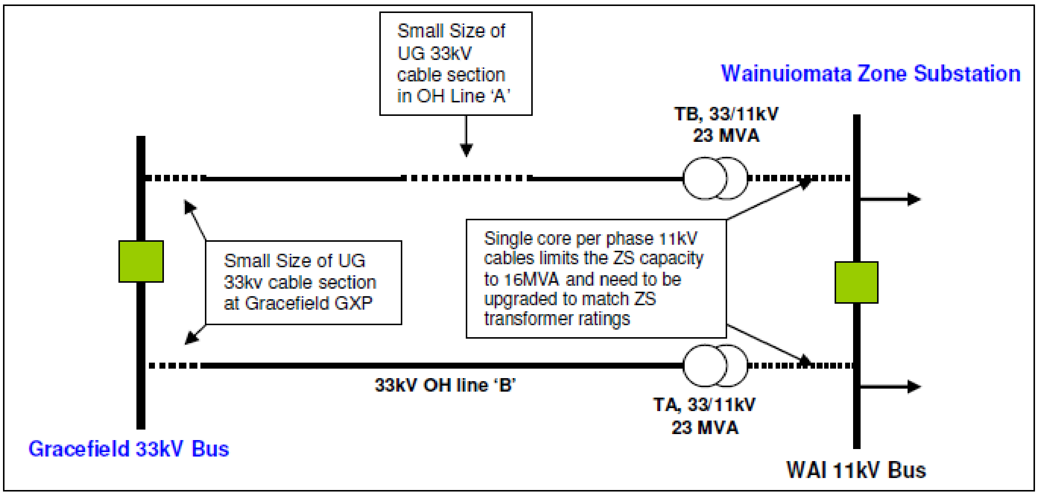

Figure 5-35 Wainuiomata Zone Substation Layout

Figure 5-36 provides a high level cost estimate for the proposed solutions for Wainuiomata zone substation.

Project Description	Cost	Year investment is required	Duration of Solution
1. Replacement of existing 11kV incomer cables with 1C, 630mm^2, Al, XLPE, 11kV cables (two per phase) **Ref 16-002**	$100,000	2016	Beyond 2030
2. Replacement of 33kV cables on Wainuiomata sub transmission circuits at Gracefield GXP (100m) **Ref 19-002**	$800,000	2019	Beyond 2030
3. Upgrade of mid-circuit cable section on 33kV Circuit 'A' (155m) **Ref 19-002**	$200,000	2019	Beyond 2030

Figure 5-36 Cost Estimate for Proposed Solutions for Wainuiomata

5.13.10. Fault Levels at CBD Zone Substations

All CBD[13] zone substations are operated as a split 11kV bus system due to the high fault levels (as a result of low impedance supply transformers) and also due to protection limits (to limit the effect of a cascade tripping should a downstream 11kV meshed ring system fail to clear a fault correctly). The average fault level on an 11kV closed bus at CBD zone substations is around 15kA which is above the 11kV asset fault ratings both at zone substations and downstream. Due to the split bus system, there is a short break in the event of a subtransmission circuit outage and there may not be true "no-break" N-1 security of supply to CBD loads should one 33kV circuit or zone transformer be out of service. The Network Control Room has

[13] The CBD area is considered to be the commercial areas supplied by Frederick St, Nairn St, University, The Terrace, Moore St, Palm Grove and Kaiwharawhara GXPs.

to close the bus section on the switchboard, or in some cases a faultman is required, which impacts on system SAIDI.

Operating the CBD zone substations in a closed 11kV bus configuration would provide “no break” security of supply should one 33kV circuit or zone transformer trip out of service. This may require alteration to existing protection settings and schemes. In some cases protection relays upgrade would be required at downstream 11kV sites to ensure there is no risk of cascade trippings back to the zone substation.

There are a number of different options available to mitigate the risk of high fault levels at CBD zone substations.

Increasing 11kV Switchgear Fault Ratings

This option involves increasing the fault ratings of the 11kV distribution switchgear at zone substations and downstream sites. To achieve this, all distribution switchgear would need to be replaced and given this high cost the option is not considered viable.

As an example, the fault level on the Frederick Street 11kV bus (when closed) is 16kA. Typically switchgear at zone substations of that era are 13.1kA (250MVA). Distribution equipment downstream is of similar rating. All new equipment being installed is rated at up to 25kA at zone substations, and up to 21kA at distribution substations with anticipation of being able to raise the fault levels in future.

High Impedance Zone Transformers

To reduce the fault level below 10kA, this option suggests installation of transformers with high winding impedance at CBD zone substations. CBD transformers are currently around 10-12% impedance, whereas a much higher impedance would be required to control fault levels. However the existing transformers at CBD zone substations are in good condition and are not due to replaced within the planning period. The benefit of this option is no additional equipment would be required and hence no space constraints would arise. The disadvantages are the high cost and very high losses in the zone transformers, as well as the premature replacement of assets.

Current Limiting Reactors and Resistors

Wellington Electricity’s CBD high voltage network is over 95% underground and almost all faults are phase-to-earth faults in the event that insulation is compromised or damaged. An option to control fault levels would be limiting the earth fault current below 10kA at CBD zone substations. This could be achieved by the use of current limiting reactors or resistors, installed at CBD zone transformer neutral points.

Another alternative would be to install bus tie reactors at CBD zone substations on the 11kV bus. The advantage of this approach is that if the load is essentially balanced on the both sides of the bus tie reactor under normal operating conditions, the reactor has negligible effect on voltage regulation or system losses.

Figure 5-37 shows the typical arrangement of a bus tie reactor in a distribution system.

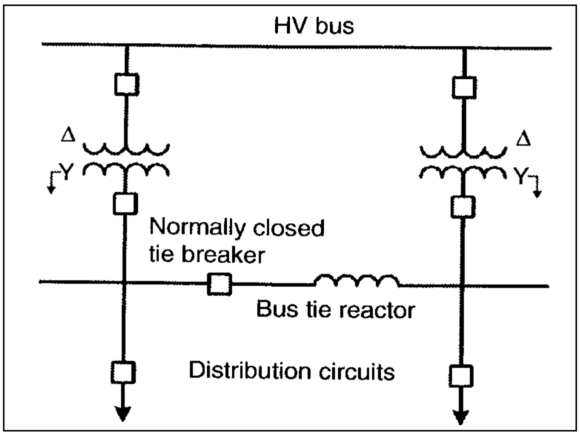

Figure 5-37 Typical Bus Tie Reactor Arrangement

There is a limitation to using bus tie reactors in CBD substations as the 11kV switchgear is of the metalclad type. Connecting the bus tie reactor to this type of switchgear would be an issue as the two sides of the bus and the circuit breaker are fully enclosed and inaccessible. Generally, these devices are better suited to outdoor switchyards so an engineering study for these connections would be required.

The key points to be considered and addressed before installation of current limiting reactors or resistors are:

- Space availability
- Protection setting review as fault level will be lowered
- Protection discrimination and co-ordination review, possible upgrade of relays
- Sensitive earth fault protection might be required due to reduced earth fault current
- Physical connection to Metalclad switchgear at CBD zone substations (for bus-tie reactors)
- CBD meshed 11kV system co-ordination

To operate CBD zone substations in closed 11kV bus mode, current limiting reactors are considered to be the best option given that very little of the other substation plant, particularly the transformers, requires replacement at this time. Further planning and research would be required to determine appropriate device sizes for limiting earth fault current at the various CBD zone substations.

Figure 5-38 provides a project cost estimate bus fault level improvements.

Project Description	Cost	Year investment is required	Duration of Solution
CBD substation bus fault level improvements Ref: 17-001, 18-001, 19-001, 20-001, 21-001, 22-001	$850,000	Annually from 2017 onwards	Beyond 2030

Figure 5-38 Cost Estimate for Bus Fault Level Improvements

5.14. 11kV Distribution System – Constraints and Development Plans

Figure 5-39 lists the 11kV feeders which, in 2018, are forecasted to be operating above 70% loading but are of a duration which still meets the relevant security criteria for the feeder type.

Feeder		Zone Substation	Loading at peak time (2018)
BRO CB08	Clearwater Cres.	Brown Owl	71%
EVA CB01	69 Miramar Ave	Evans Bay	70%
EVA CB03	Batten St	Evans Bay	70%
KAR CB 02	Dasent St	Karori	71%
KOR CB 05	TAB Head Office	Korokoro	70%
KOR CB 12	Hutt RD C	Korokoro	70 %
MAI CB 06	Leisure Centre	Maidstone	77%
MEL CB 03	Boulcott Street	Melling	73%
MEL CB 11	Connolly St	Melling	70%
MOO CB 14	50 Thorndon Quay	Moore Street	76%
NGA CB 04	Jarden Mile	Ngauranga	78%
POR CB 05	Lyttleton Ave	Porirua	70%
TRE CB 12	Gower St	Trentham	73%
WAT CB 05	Brook St	Waterloo	78%

Figure 5-39 11kV Feeder Loading Forecast – Short Duration Peak Loading

Monitoring of these feeders will continue. If the duration or magnitude of the loading is found to exceed the security criteria for the feeder type, solutions will be identified for reducing the loading, or reinforcing the network to ensure compliance with the security criteria.

Figure 5-40 lists the 11kV feeders which, in 2018, are forecasted to be operating above 70% loading for sustained periods at peak time during normal operation and therefore are likely to be in breach of the security criteria for that feeder. These feeders have been, or are in the process of being, assessed for network reconfiguration and augmentation solutions to the high loading. Figure 5-41 lists the feeders which are identified to have constraints in the period 2018-2023.

Feeder		Zone Substation	Loading at peak time (2018)	Loading to exceed N-1 Criteria
HAY 2722	Silverstream	Haywards 11kV	91%	2012
TAW CB 13	Oxford St	Tawa	73%	2012
PAL CB 11	Parade	Palm Grove	90%	2013
WAN CB 05	Postage Drive	Waitangirua	90%	2013
IRA CB 02	33 Ludlam St	8 Ira Street	87%	2013
WAT CB 03	Hautana St	Waterloo	81%	2013

Feeder		Zone Substation	Loading at peak time (2018)	Loading to exceed N-1 Criteria
KAI CB09	209 Hutt Rd	Kaiwharawhara	79%	2013
MOO CB 02	National Library	Moore St	84%	2014
MAI CB 11	42 Lane St	Maidstone	78%	2015
PAL CB 01	312 Adelaide Rd	Palm Grove	77%	2015
GRA CB 02	Gracefield Rd A	Gracefield 11kV	77%	2016
UNI CB 03	84 Fairlie Terrace	University	High loading on T1 bus section	N/A

Figure 5-40 11kV Feeder Loading Forecast – Sustained High Loading at 2018 (5 years)

Feeder		Zone Substation	Feeder Forecast loading at peak time (2018-2023)
EVA CB01 (ring)	69 Miramar Ave	Evans Bay	55%
EVA CB03 (ring)	Batten Street	Evans Bay	55%
JOH CB 06	Johnsonville Swimming Pool Sub	Johnsonville	67%
KAI CB 09	209 Hutt Road	Kaiwharawhara	66%
KOR CB 02	Western Hutt Road South	Korokoro	75%
KOR CB 04	NZR Petone	Korokoro	70%
KOR CB12	Massey Street	Korokoro	74%
KEN CB 09	Broken Hill Road A	Kenepuru	67%
MAN CB 02	NZR Goodshed Road	Maidstone	67%
NAI CB 14	92 Washington Ave	Nairn Street	66%
SEA CB 12	Hutt Park Sports Centre	Seaview	66%
UNI CB11	Epuni Street	University	73%
WAT CB 03	Caduceus Place Switching Station	Waitangirua	66%

Figure 5-41 11kV Feeder Loading Forecast – Sustained High Loading at 2023 (10 years)

Palm Grove Feeders 1 and 11 have loading constraints which are linked with wider CBD supply capacity constraints. The building of a new zone substation in the CBD will allow these to be reconfigured. Presently there is short term solution available to off load some these feeders onto interconnecting neighbouring feeders by shifting open points.

Loading constraints on Waitangirua Feeder 5 are linked to a large subdivision development which will continue to grow over the coming years. As part of this work, significant reconfiguration of the 11kV network is required to supply the subdivision and to relocate existing overhead lines. This project will commence in mid 2013 as a customer initiated project.

5.14.1. Operational Solutions to Identified High Load Feeders

Many of the high load feeders identified can be off loaded by shifting open points to utilise the existing capacity in adjacent feeders, without the need for further investment in the network. Figure 5-42 lists the constrained feeders which can be off loaded onto adjacent feeders.

Feeder	Load moved to	Forecast loading at peak time (2018)	
		Existing	Proposed
IRA CB 02	IRA CB04	87%	75%
HAY CB 2722	TRE CB05	91%	75%
KAI CB 09	KAI CB06	79%	66%
KEN CB 09[14]	TAW CB13	87%	68%
MAI CB 11	MAI CB02	78%	53%
WAT CB 03	SEA CB12	81%	66%

Figure 5-42 Proposed Open Point Configurations to Reduce Loadings on Feeders

This proposed open point configuration would reduce feeder loadings below or close to 66% at peak load time. The remaining high load feeders not yet addressed require a solution such as reinforcement work to increase capacity, or to reduce the feeder loadings via other methods such as demand side management, temporary generation or other means.

5.14.2. Feeders Requiring Investment for Non-operational Solutions

The feeders which have constraints that cannot be easily resolved in the short to medium term by operational means are likely to require network investment and reinforcement. A description of each of the major 11kV feeder reinforcement projects is discussed below.

5.14.2.1. Ira Street Feeder 2

Ira Street feeder 2 supplies a mixture of residential and commercial load in the Seatoun area and has a peak demand of 5.50MVA, which is 80% of the feeder rating. There is an option to shift some of Ira Street feeder 2 load onto Ira Street feeder 4, which will reduce the loading on Ira Street feeder 2. The loading at Ira Street feeder 2 after load transfer will be still above 66% loading limit and investment would be required to reduce the loading at Ira Street 2.

[14] Load shift from Kenepuru 09 to Tawa 13 to take place after the Tawa 13 cable upgrade (Refer to Section below)

There is another constraint on this feeder which also needs to be addressed. There is small section of feeder cable between Broadway substation and Devonshire Road substation as highlighted in figure 5-43 below, which limits the capacity of Ludlam Street CB3 distribution feeder to 200A. This part (Ludlam St CB3) of Ira Street feeder 2 provides back up supply to Evans Bay zone 1 ring load and also supplies key Commercial loads. During normal operation the peak demand on this section of Ira Street feeder 2 is below 200A but during contingency operation it presents a risk to this section of cable and creates an unnecessary constraint on the network ratings.

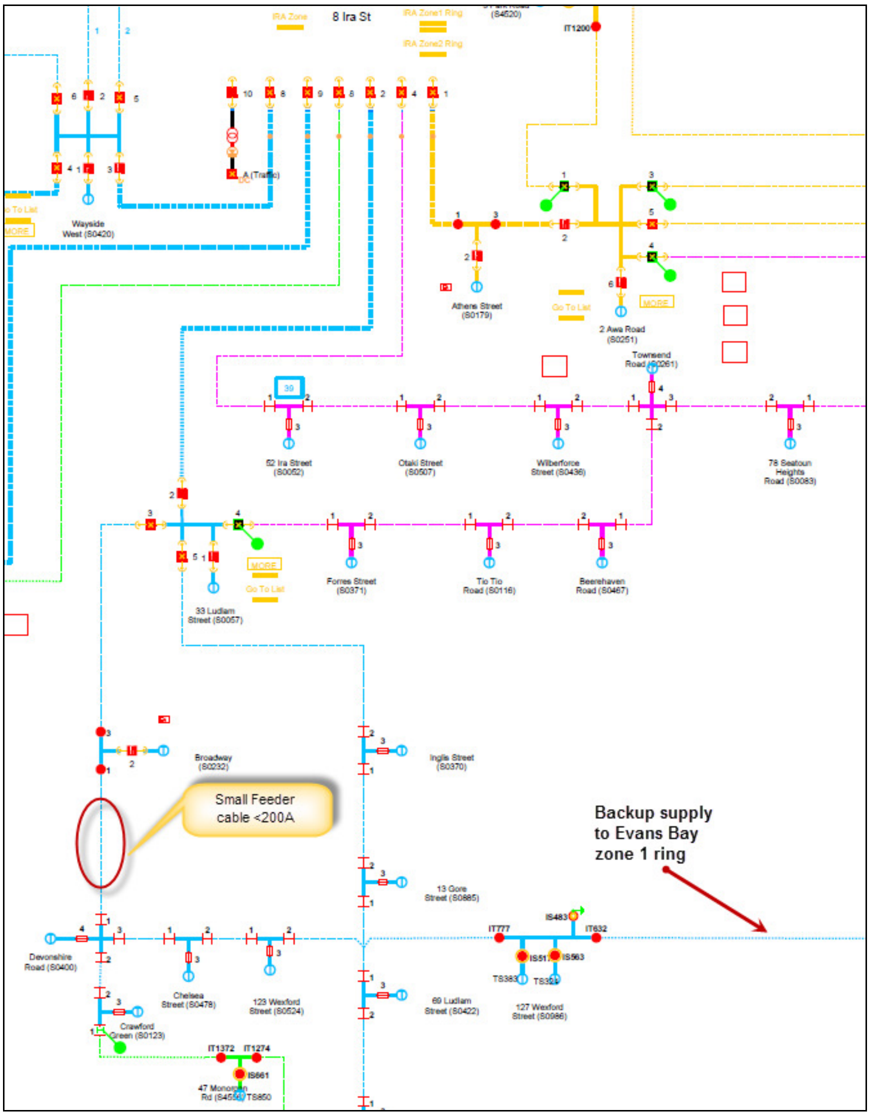

Figure 5-43 Identified constraint on Ira Street Feeder 2

There are different options to address the identified issues. One option would be to install a new feeder at the Ira Street zone substation and connect into Ludlam Street CB3 feeder along with upgrading a small section of cable with 350A rated cable. The new feeder will pick up half of the Ira Street feeder 2 load and will provide full backup to the 69 Miramar Ave feeder, This option does not involve significant cabling work apart from replacing the undersized cable between Broadway and Devonshire Road substation. The Ludlam Street CB3 feeder runs outside the Ira Street zone substation and the feeder could be connected outside the zone substation.

In the short term a network load flow study will be undertaken to identify the optimum solution for addressing the identified Ira Street feeder 2 constraints. Figure 5.44 provides the estimate cost for installing a new feeder at Ira Street substation and replacement of the undersized cable.

Project description	Cost	Year investment is required	Duration of Solution
New Feeder at Ira Street substation to off load Ira Street feeder 2 and Evans Bays zone 1 ring feeders plus replacement of 188m of undersized cables **Ref 14-002**	$400,000	2014-15	Beyond 2025

Figure 5-44 Cost Estimate for Proposed Solutions for Ira Street Feeder 2

5.14.2.2. Gracefield Feeder 2

Gracefield Feeder 2 supplies the Eastbourne area which is mostly residential with a winter peak load demand of 3.4MVA. The full capacity of Gracefield Feeder 2 is 5.37MVA with loading of 65% at peak load times (2012) forecasted to grow to 77% by 2017. This loading (77%) is outside the planning and security criteria for this type of feeder.

There are two network options that would address the loading concerns at Gracefield. One option is to increase the capacity of the existing feeder and the second option involves shifting the load onto interconnecting feeders.

Increasing the feeder capacity involves replacing the existing 11kV feeder cable by installing a new three core 300mm^2, aluminium cable, which would require replacing more than 2 km of existing cable. This option of cable replacement is not an efficient solution due to the cost of installing such a length of cable.

The second option involves shifting a portion of the load from Gracefield Feeder 2 to Gracefield Feeder 8. Gracefield Feeder 8 follows the same route as Gracefield Feeder 2 but has lower loading. However the capacity of Gracefield Feeder 8 is limited due to around 500m of undersized three core, 95mm^2, aluminium cable installed between Seaview Wharf substation and Days Bay switching station.

This proposed plan is to shift the last six distribution substations at the end of Gracefield Feeder 2 onto Gracefield Feeder 8 by closing the normally open point CB03 at Days Bay switching station. This will reduce the loading on Gracefield Feeder 2 cable to below 66% at peak load time. Implementing the proposed plan requires replacement of the existing undersized cable on Gracefield Feeder 8 with three core, 185mm^2, aluminium cable before the proposed switching could be carried out.

Figure 5-45 provides the estimated cost to replace the undersized cable between Seaview wharf and Days Bay switching station.

Project description	Cost	Year investment is required	Duration of Solution
Replace existing 95mm^2, Aluminium cable with 185mm^2, Aluminium on Gracefield Feeder 8. Reconfigure existing open points **Ref 15-002**	$420,000	2015-16	Beyond 2025

Figure 5-45 Cost Estimate for Proposed Solutions for Gracefield Feeder 2

5.14.2.3. Haywards Feeder 2722

Haywards feeder 2722 supplies the Silverstream area and has a residential load profile. The 2012 peak demand on Haywards 2722 was 5.10MVA recorded in June. This feeder also supplies the Silverstream On Track substation (Kiwi Rail electrified rail), which contributes to the high loading on this feeder.

Haywards feeder 2722 is supplied from Transpower's Haywards 11kV GXP. It shares an open point with Trentham feeder 5 and around 500kVA of load will be moved onto Trentham 5 in 2013 as part of a customer load connection project and subsequent reconfiguration of that part of the network. This will reduce the loading on Haywards feeder 2722 but peak demand on this feeder will still be above the feeder planning criteria limits. The most feasible option at present would be to install a new feeder at Haywards and permanently shift the On Track substation on to the proposed new feeder. A detailed load flow study will be undertaken to find the optimum solution to the address the identified constraints on this feeder. Figure 5-46 provides the estimated cost to reduce the loading on Haywards feeder 2722.

Project description	Cost	Year investment is required	Duration of Solution
New Feeder at Haywards 11kV GXP to offload feeder 2722 including new feeder cable **Ref 14-005**	$500,000	2014-15	Beyond 2025

Figure 5-46 Cost Estimate for offloading Haywards 2722

5.14.2.4. Moore Street New Feeder

Moore Street zone substation supplies part of the Wellington CBD area around Parliament, serving government offices and departments, large commercial buildings, Westpac Stadium, Centerport and the central railway station. It has a summer peak and a typically commercial load profile.

Load growth is high around the Centerport and Waterloo Quay area with recent customer requests for load connections over 500kVA. At present Moore Street zone 2 ring feeders (CB12 and CB14) supply the load around these areas. As the demand increases over the time, it has been found that any future load connection more than 1.0MVA would overload the zone 2 ring. The overloading of the zone 2 ring could result in cascade failure should one feeder in the ring be out of service. This issue of zone 2 ring overloading needs to be addressed so that future load requests can be supplied.

Two options exist to reduce the loading on the Moore Street zone 2 ring feeders

Option 1: Convert to Radial Feeder System

This option involves converting the existing zone 2 ring feeders into open ended radial feeders and would require balancing of the feeder loads so that each feeder is evenly loaded and within the planning criteria limits of 66% loading. The radial feeders will provide lower reliability when compared to the present ring system. Additionally, there are limited back feed options available due to the high peak load on neighbouring interconnecting feeders unless a new feeder is installed to increase overall capacity in the 11kV system in this area, and to off load other feeders to provide lower loadings and greater interconnection.

This option of converting the zone 2 ring feeders into radial feeders is not recommended as it would lead to reduced security of supply, and potentially poorer performance in this area of network compared to what is presently offered to consumers.

Option 2: New 11kV Feeder

This option involves the addition of a new feeder into the existing zone 2 ring or a new radial feeder from Moore Street zone substation, and picking up future load. It requires installation of a new circuit breaker on the T2 side of the 11kV bus at Moore Street.

There are two possible routes to install the new feeder cable into the Waterloo Quay and Centerport area, either along Bunny Street or crossing the train tracks. The route along Bunny Street is longer and will require a greater length of feeder cable compared to the rail track crossing route. Initial discussions with Kiwi Rail and the Stadium have indicated that there would be no objections to installing cable in a duct on the pedestrian overpass, however this is in concept only and is subject to further consultation. The proposed feeder route is shown in figure 5-47.

Figure 5-47 Proposed new feeder layout from Moore Street

Installing a new feeder from Moore Street into Waterloo Quay as shown in the above diagram would be the preferred option and most cost effective option. This would provide around 4-6MVA of capacity into Waterloo Quay and Centerport area to allow connection of future load, and to alleviate existing high loading.

The benefits of this option are evenly loaded zone 2 ring feeders, reduced likelihood of a cascade tripping should one feeder be out of service under the present configuration, and provision of additional capacity which is available for future load growth. By retaining the ring configuration the existing levels of security and reliability will be retained.

Figure 5-48 provides the estimated cost for this new feeder option.

Project Description	Cost	Year investment is required	Duration of Solution
1. Installation of a new feeder cable in Thorndon Quay, Pedestrian overpass and substation	$600,000	2013	Beyond 2030
2. New circuit breaker with protection relays at Moore Street zone substation	$75,000	2013	Beyond 2030

Project Description	Cost	Year investment is required	Duration of Solution
3. Switchgear extension at distribution substation (addition of new circuit breaker)	$50,000	2013-14	Beyond 2030
Total **Ref 13-004**	**$725,000**		

Figure 5-48 Cost Estimate for New Feeder into Freyberg Building Substation

5.14.2.5. Naenae Feeder 6

Naenae Feeder 6 has been found to have a capacity constraint and is limited to 3.72MVA due to the initial section of the feeder being an undersized cable (3C, 95mm^2, Al, XPLE). The feeder loading at peak winter times is above 75% and this section constrains the remainder of the feeder. Replacing this small section of cable with 3C, 300mm^2, Al, 11kV cable will increase the capacity of feeder by around 3.0-3.5 MVA. Figure 5-49 shows the cable section required to be replaced.

This constraint is currently a high risk because this undersized segment of feeder carries full load at all times and an outage on this section due to overloading would result in total loss of supply to whole feeder. Additionally, an increased rating will provide increased security to other Naenae feeders as this feeder will be able to offload those feeders during outages, whereas currently this is not possible.

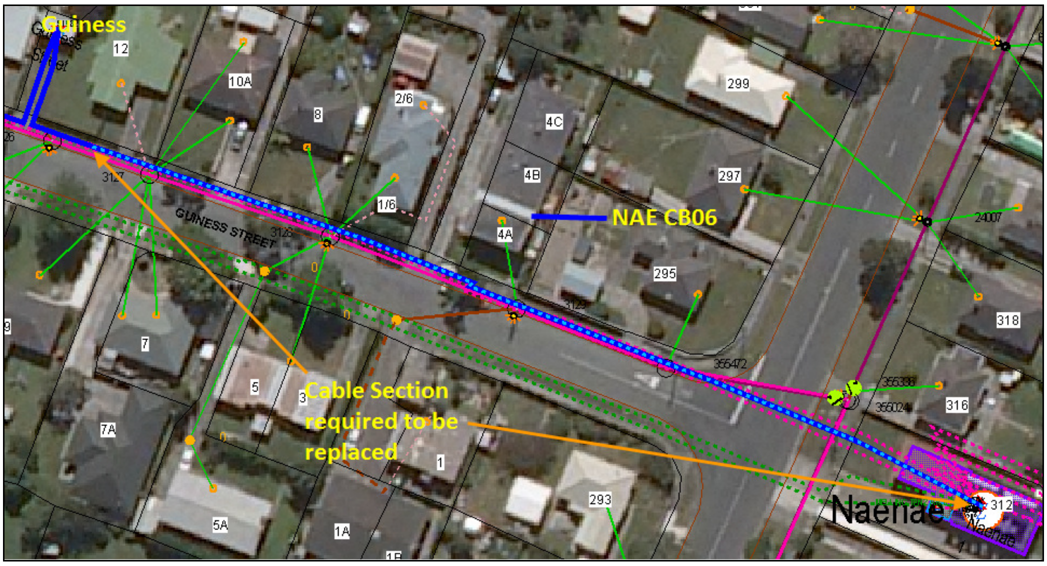

Figure 5-49 Overview of Proposed Naenae Cable Replacement

Figure 5-50 provides the estimated cost for this new feeder option.

Project Description	Cost	Year investment is required	Duration of Solution
Replace existing 165m of 3C, 95mm^2, Al cable with 3C, 300mm^2, Al, 11kV cable **Ref 13-003**	$150,000	2013	Beyond 2030

Figure 5-50 Cost Estimate for Naenae Cable Replacement

5.14.2.6. Palm Grove Feeder 11

The 2012 peak demand on Palm Grove feeder 11 was 5.60MVA, which is 85% of its capacity. This feeder is the highest loaded feeder in the Palm Grove zone 1 ring. The zone 1 ring has a peak demand of 11.6MVA, however the loading on Palm Grove zone 1 ring feeders are uneven with Palm Grove 11 being 85% loaded rather than sharing the load evenly.

A planning study will be undertaken to determine the optimum solution to address the identified constraints. One of the possible solutions would be to install a new feeder in the Palm Grove zone 1 ring. Figure 5-51 below provides the estimated cost for this possible solution along with timeframe for this work.

Project Description	Cost	Year investment is required	Duration of Solution
Reinforcement of Palm Grove zone 2 ring to reduce loading at Palm Grove feeder 11 **Ref 16-001**	$500,000	2016	Beyond 2030

Figure 5-51 Cost Estimate for Palm Grove feeder 11 reinforcement

5.14.2.7. Tawa Feeder 13

Tawa Feeder 13 supplies residential load on the north side of Tawa zone substation, with a peak demand of 2.41MVA. Though the peak load is not high, the capacity of the feeder is limited by the initial part of the feeder being undersized. The first 1.15km of this feeder has 95mm^2, aluminium cable which limits the capacity of the feeder to 3.72MVA. To improve the capacity of this feeder and reduce the constraints, the first section of Tawa Feeder 13 needs to be upgraded. The network standard size for feeders leaving zone substations is three core, 300mm^2, aluminium cable to provide the best rating for the front section of the feeder.

One option is to replace the existing 95mm^2, aluminium cable section and install new three core, 300mm^2, aluminium cable over the existing route in the same configuration up to the 4 Lyndhurst Street substation. This will increase the feeder capacity by 3.15MVA to around 6.8MVA. The total length of cable requiring replacement would be 1.15km.

The second option would be to install a new high capacity cable from the Tawa Feeder 13 circuit breaker and connect into Mascot substation as shown in Figure 5-52. The new cable will become the front section of the Tawa Feeder 13 feeder and the existing 95mm^2, aluminium (Al) cable will become the tail end of Tawa Feeder 13. The total length of proposed cable route is about 600m which is 525m shorter than the route required if replacing the existing cable as per option one. A shortcut can be taken by utilising walkways between blocks rather than following the road but it would cost more than following the road route even though it is around 135m shorter in route length. The high cost of using the walkway arises due to concrete steps needing reinstatement and the location a large diameter stormwater main which would make trenching difficult. It is also recommended as part of the works to install a new three way ring main unit outside the Tawa zone substation between the existing Tawa Feeder 13 cable (95mm^2 Al) and the proposed new cable, which will provide an alternative supply to the tail end of Tawa feeder 13.

As a part of this project, a 150mm duct has already been installed in The Drive, in conjunction with Wellington City Council storm water pipe installation work in late 2012. This duct covers 70% of the proposed cable route and will reduce the overall project cost and the amount of work required.

The second option of installing a new feeder cable and connecting into the Mascot Street substation is recommended as it provides the lowest cost solution to the existing constraints and also provides additional capacity for future load growth in this area.

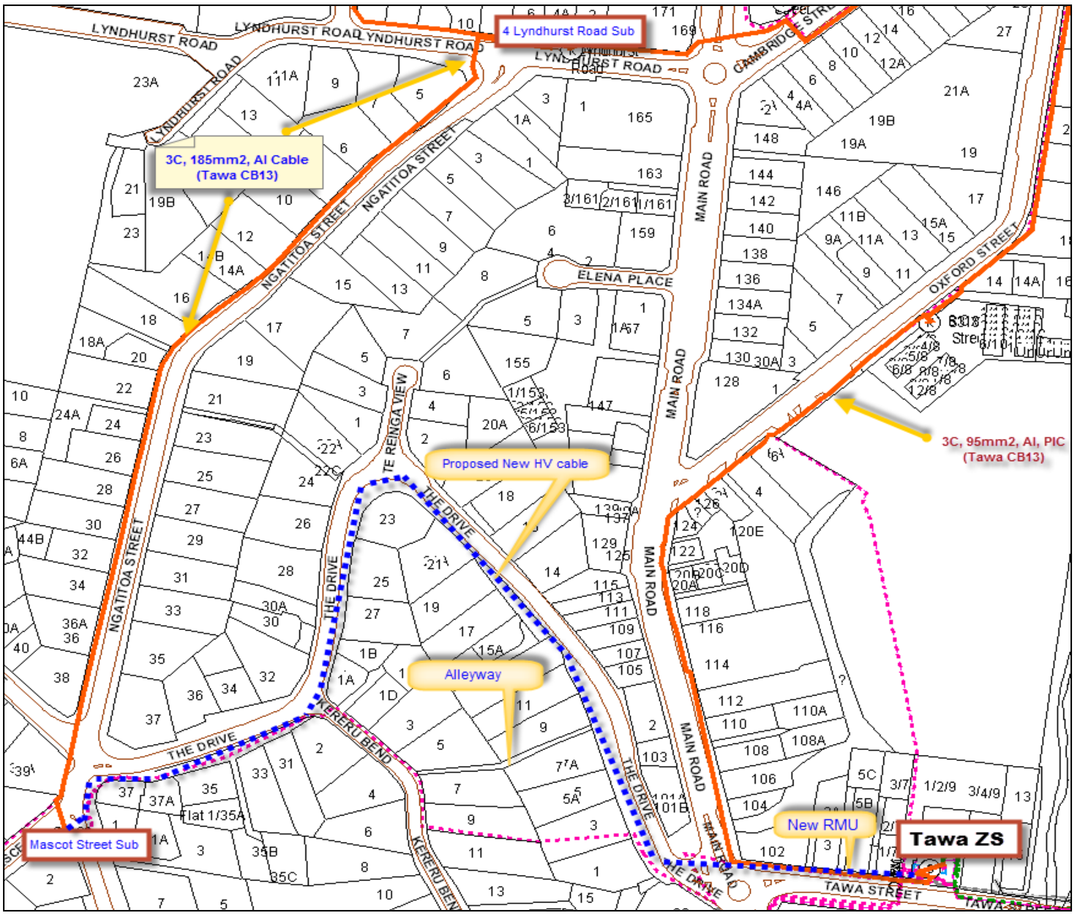

Figure 5-52 Overview of Proposed Tawa Feeder 13 Cable Reinforcement

The estimated cost for the preferred option of installing a feeder cable is shown in Figure 5-53.

Project Description	Cost	Year investment is required	Duration of Solution
Install a new cable from Feeder circuit Breaker 13 to Mascot Street substation and replacement of switchgear at this substation.	$550,000	2013	Beyond 2030
Install new three way ring main unit outside Tawa zone substation	$35,000	2013	Beyond 2030
Total **Ref 13-001**	**$585,000**		

Figure 5-53 Cost Estimate for Tawa Feeder 13 Cable Reinforcement

5.14.2.8. University Feeder 3

The peak demand on University feeder 3, recorded in June 2012, was 2.8MVA. University feeder 3 has a commercial load profile. The feeder is supplied from the T1 side of the bus, which has high loading compared to the T2 side of the bus. The existing configuration of feeders at University zone substation is shown in Figure 5-54. The T1 side of the bus has five feeders and the T2 side of the bus has four feeders with one as a spare feeder. The 11kV bus at University is operated normally open to minimise fault levels, and therefore loading on the two transformers is not evenly shared.

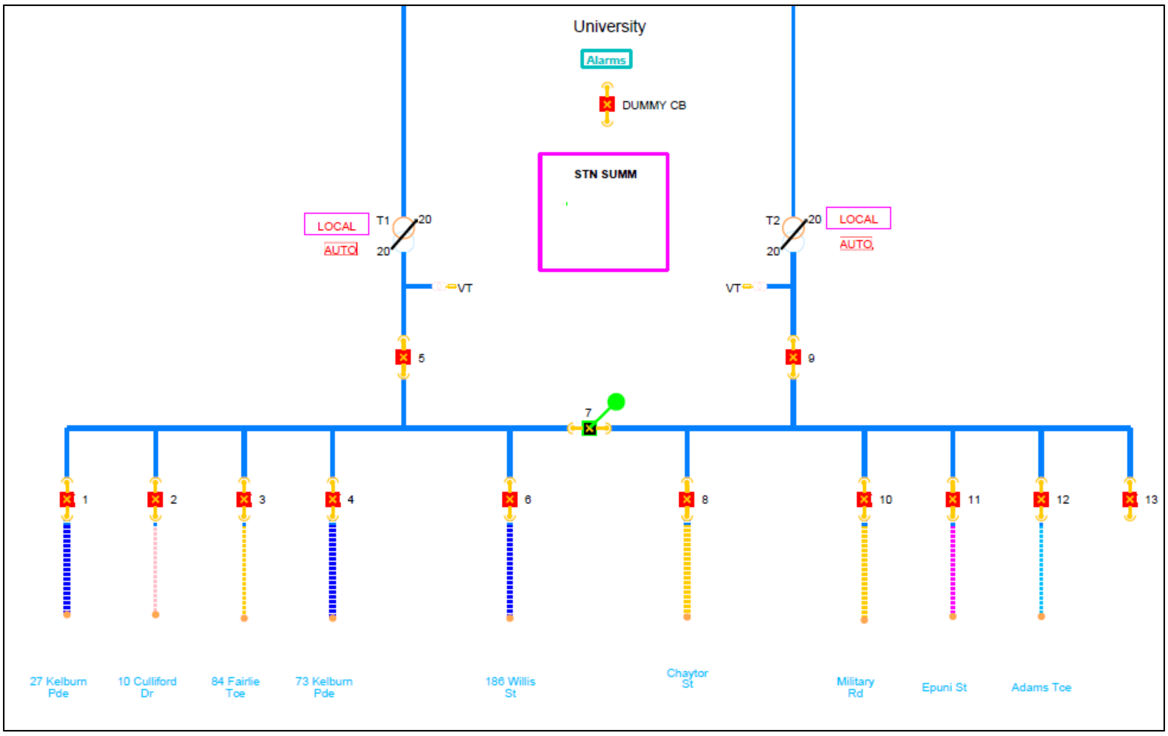

Figure 5-54 University Zone substation layout

The T1 side of the bus at University supplies the commercial load around the Wellington CBD and T2 supplies the residential load around Kelburn and Aro Valley. The T1 peak load is higher than the T2 load. Due to the high loading on the T1 transformer during the day, the transformer has a 15-20°C higher temperature than the T2 transformer. This has an impact on the transformer age and condition. Reducing the loading on the T1 side of bus at University would reduce the T1 temperature during peak time. The temperature profile at both T1 and T2 transformer is shown in figure 5-55, which is similar to their respective load profiles. External cooling and building ventilation is also part of the solution being investigated.

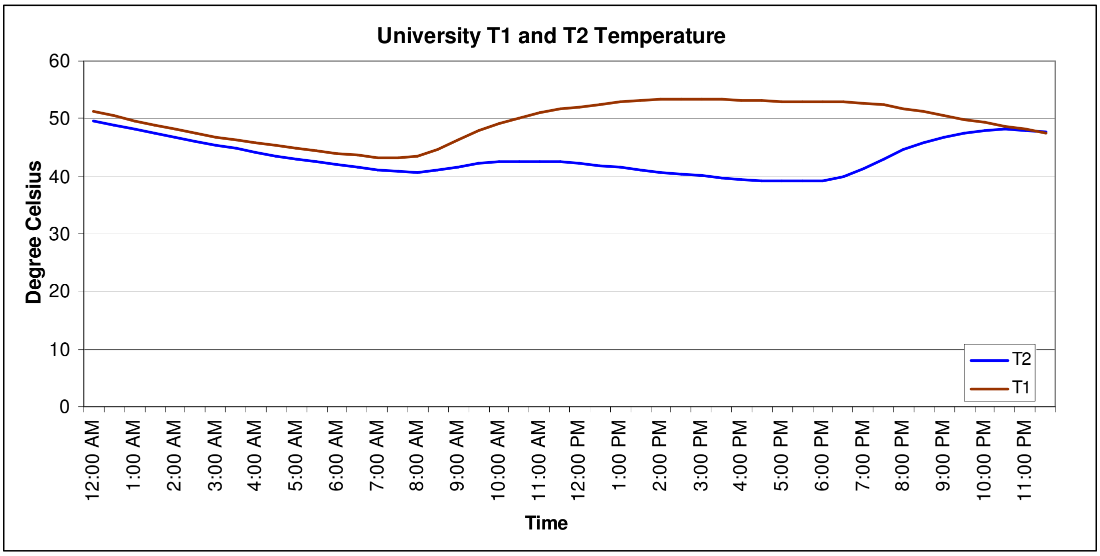

Figure 5-55 Transformers temperature profile at University zone substation

There are different options to reduce the loading on T1 which includes shifting load from University T1 side feeders to neighbouring interconnecting feeders or shifting one of the T1 side feeders onto the T2 side of bus. There is spare feeder bay available on the T2 side of the bus at University zone substation and shifting University CB3 feeder onto spare circuit breaker 13 would evenly balance the loading on both the zone transformers at University.

A detail planning study will be undertaken in 2013 to fully explore the other options of balancing the loading on both the University zone transformers.

Figure 5-56 provides the estimated cost for balancing the loading at University zone transformers.

Project Description	Cost	Year investment is required	Duration of Solution
Balancing the loading on University zone transformers – Shifting CB2 onto T2 side of bus **Ref 14-001**	$150,000	2014-15	Beyond 2030

Figure 5-56 Cost Estimate for University feeder 3 reinforcement

5.15. Proposed Wellington Electricity Network in 2022

The figure below provides the proposed 2022 overview of the Wellington Electricity network. This is how it is expected to look given current growth trends and considering the required capacity and security levels. As described in this section, over the next 10 years three new zone substations are planned to be constructed to supply areas around the Wellington CBD, Grenada and Whitby/Pauatahanui. The proposed reinforcement of the sub transmission network, which would involve replacement of aged and highly utilised gas and oil filled cables with new XLPE cables, is also shown as dotted orange colour lines in the figure below. At the completion of this work, the Wellington Electricity network will provide a high level of resilience within the sub transmission network, and have sufficient capacity within required security levels by the end of 2022.

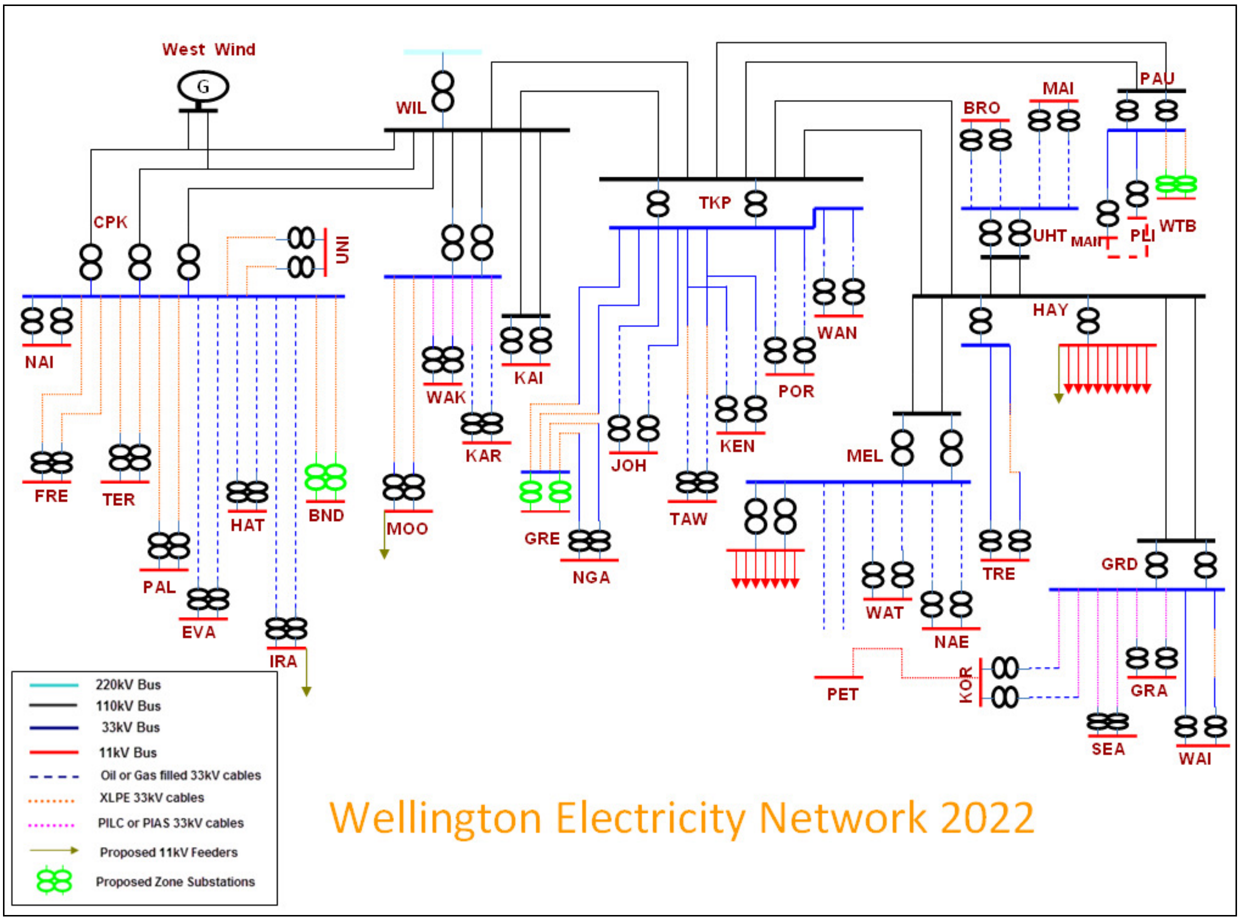

Figure 5-57 Proposed Wellington Electricity Network Overview - 2022

5.16. Investment Programme - Growth, Customer Connections and Asset Relocations

Major network investment works covered in this section include new development works to maintain security levels driven by system growth, and to enable customer connection and asset relocation work to occur. Asset replacement and renewal projects to address asset age or condition are covered in Section 6 (Lifecycle Asset Management).

5.16.1. Major Network Investments for the Current Year

The following major projects and programmes of work are budgeted and expected to take place or commence in the 2013 calendar year.

5.16.1.1. 2013 Growth, Security and Reinforcement Projects

Mana-Plimmerton Zone Substation Reinforcement – Special Protection Scheme	
Driver: Growth Estimated cost: $250,000	The 11kV tie line between Mana and Plimmerton has a capacity shortfall of 4MVA should the 33kV circuit supplying Mana zone transformer be out of service. A special protection scheme with inter trip and close is going to be implemented to manage the load during contingency situations. For more details, refer to section 5.13.4

Tawa Feeder 13 Reinforcement Project – 2013	
Driver Security, Capacity Estimated cost: $585,000 Ref: 13-001	Tawa Feeder 13 supplies residential load on the north side of Tawa zone substation, with a peak demand of 2.41MVA. Though the peak load is not high, the capacity of the feeder is limited by the initial part of the feeder being undersized. The first 1.15km of this feeder has 95mm^2, aluminium cable which limits the capacity of the feeder to 3.72MVA. To improve the capacity of this feeder and reduce the constraints, the first section of Tawa Feeder 13 needs to be upgraded as detailed in section 5.14.2.7.

Palm Grove Subtransmission replacement - 2013	
Driver: Capacity, Condition Estimated cost: $9 million Ref: 13-002	The Palm Grove subtransmission N-1 capacity does not match the zone substation transformer firm capacity and has a shortfall of 6.0 MVA. The current peak load at Palm Grove zone substation exceeds the subtransmission N-1 capacity. The best option is to replace the existing gas filled 33kV cables with new XLPE cables as explained in section 5.13.6.

Naenae Feeder 6 Reinforcement – 2013	
Driver: Capacity Estimated cost: $150,000 Ref:13-003	Naenae Feeder 6 has been found to have a capacity constraint and is limited to 3.72MVA due to the initial section of the feeder being an undersized cable (3C, 95mm^2, Al, XPLE). The feeder loading at peak winter times is above 75% and this section constrains the remainder of the feeder. Replacing this small section of cable with 3C, 300mm^2, Al, 11kV cable will increase the capacity of feeder by around 3.0-3.5 MVA. Refer to section 5.14.2.5 for details.

Moore Street New feeder – 2013	
Driver: Security, Condition Estimated cost: $750,000 Ref:13-004	The load growth is high around the Centerport and Waterloo Quay area with recent customer requests for load connections. At present Moore Street zone 2 ring feeders (CB12 and CB14) supply the load around these areas. As the demand is increased over the time and any future load connection more than 1.0MVA would overload the zone 2 ring. A new feeder at Moore Street zone substation would be required to supply the future load demand around Waterloo Quay and Centerport area. For details refer to section 5.14.2.4.

5.16.1.2. HV Reinforcement - General

This is an aggregated budget allowance of $400,000 for minor HV network reinforcement projects that are not able to be directly attributed to individual customers. Projects expected in 2013 include installation of a new length of cable for, extension of the 11kV network into Mortimer Terrace due to low voltage issues and other small network reconfiguration and reinforcement projects.

5.16.1.3. LV Reinforcement - General

This is an aggregated budget allowance of $250,000 for minor LV network reinforcement projects that are not able to be directly attributed to individual customers. Examples of such projects include installing a new berm substation in response to network loading or voltage concerns, or a 400V cable reinforcement project.

5.16.1.4. Customer Growth and Relocations

These projects have been aggregated in the budget as per the categories below. Overall, the budgeted expenditure for 2013 of $5.8 million compares slightly lower to the 2012 forecast of $6.0 million. This is attributed to reaching a plateau with the recent economic slow down. It should be noted between 2005 and 2009, customer expenditure was, on average, $7.5m per year.

New Connections

For the second consecutive year running the number of residential building consents issued is subdued. This is a continuing sign of the slow economy combined with the removal of the ability to claim building deprecation which is having an impact on the small residential developments.

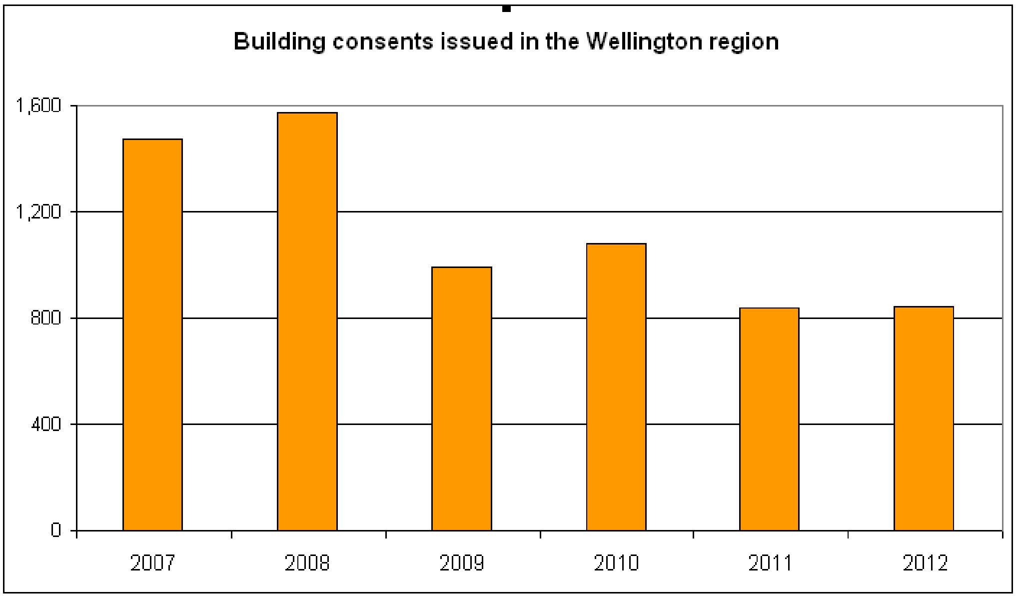

Figure 5-58 Number of Building Consents Issued in Wellington Region

While 2013 budgets for new connections are higher than for the 2012 year end forecasts, it is based on the last four year rolling average.

Substations

The slight increase in customer substation expenditure is due to a number of data centre developments, each requiring network redundancy above 1MVA. Overall substation related spend, including transformer capacity changes, is closely aligned to levels seen in the past 4 years at $2.7 million.

Subdivisions

While small and infill subdivisions look to remain at similar levels of previous years, local developers continue to show little appetite for large scale residential (>100 lots) or business park subdivisions. New industrial property development activity has all but ceased because of insufficient demand and surplus vacant sites that can be easily converted for tenancy needs. While a number of potential medium size subdivision projects have been identified it is expected that some may not be undertaken in the 2013 year. However this is offset by smaller subdivision projects being undertaken although not allowed for in original expenditure. The budget allocation for subdivisions in 2013 is $1.3 million.

Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included within the customer substation area of the Customer Connection forecasts.

Relocations

An allowance in 2013 of $887,000 for relocation work, initiated from NZTA and Councils, as well as other customer initiated relocations has been made based on an average of the previous four years.

5.16.2. Prospective Investments for 2014 – 2018

Projects included in this section are less certain in nature. Whether or not they proceed, and their timing, will depend largely on whether forecast load growth materialises. It is possible that over the period before construction of any project must be committed, Wellington Electricity may identify more cost effective, including non-network, approaches that will supply the required load in accordance with the planning criteria

Wilton Subtransmission protection upgrade – 2014	
Driver: Security, Condition Estimated cost: $450,000 Ref: 14-004	Replace the existing cable differential protection scheme on Waikowhai and Karori 33kV feeders with new relays during conversion of the Wilton 33kV bus outdoor to indoor conversion which Transpower has indicated will occur in the first part of 2014. The details for this project are provided in section 5.12.7 of this chapter.

University Feeder 3 Reinforcement – 2014	
Driver: Growth, Security Estimated cost: $150,000 Ref: 14-001	Due to high loading on T1 side of University 11kV bus, the T1 transformer has high loading compared to the T2 transformer. To balance the loading on both transformers at University, feeder 3 will be shifted onto to the T2 side of bus. This will evenly balance the loading on both zone transformers at University as shown in section 5.14.2.8.

New 11kV Feeder at Haywards 11kV GXP – 2014	
Driver: Growth, Security Estimated cost: $500,000 Ref: 14-005	Due to the high loading on Haywards feeder 2722, investment will be required to install a new feeder at the Haywards 11kV GXP to offload Haywards feeder 2722. This will provide spare capacity into the Silverstream area to meet high future growth and to manage existing high loading including that of the Kiwirail traction substation. The detail of this project is provided in section 5.14.2.3.

Mana-Plimmerton Zone Substation Reinforcement – Special Protection Scheme - 2014	
Driver: Growth Estimated cost: $250,000 Ref: 14-006	The 11kV tie line between Mana and Plimmerton has a capacity shortfall of 4MVA should the 33kV circuit supplying Mana zone transformer be out of service. A special protection scheme with inter trip and close is going to be implemented to manage the load during contingency situations. For more details, refer to section 5.13.4

Trentham Subtransmission Protection Upgrade - 2014	
Driver: Security, Condition Estimated cost: $400,000 Ref: 14-003	Upgrade of the Trentham 33kV protection from Haywards GXP to Trentham Zone substation to improve performance and to include pilot wire supervision to avoid double circuit outages on the 33kV circuits as a result of a single failure in the communications circuit. Refer to section 5.13.7 for details.

Ira Feeder 2 Reinforcement - 2014	
Driver: Growth, Security Estimated cost: $400,000 Ref: 14-002	Installation of a new feeder at Ira Street zone substation and connect into Ludlam Street CB3 feeder along with upgrading a small section of cable on this feeder. The new feeder will pickup half of Ira Street feeder 2 load and will provide full backup to 69 Miramar Ave feeder as explained in section 5.14.2.1. .

Takapu Road Subtransmission protection upgrade - 2015	
Driver: Security, Condition Estimated cost: $600,000 Ref: 15-004	Replace existing line/cable differential protection schemes with new relays during conversion of the Takapu Rd 33kV bus outdoor to indoor conversion which Transpower has indicated will occur in 2015.

New Wellington CBD Zone Substation – 2015/16	
Driver: Growth, Security Estimated cost: $20 million Ref: 15-001	Construction of a new 33/11kV zone substation in the Wellington CBD to address loading issues and improve security of supply to the CBD. Including reconfiguration of 11kV feeders. Investment in a single new zone substation may defer expenditure required to increase subtransmission and transformer capacity at multiple Wellington City zone substations around the CBD. For detail, refer to section 5.13.1.

Gracefield Feeder 2 Reinforcement - 2015	
Driver: Growth Estimated cost: $420,000 Ref: 15-002	Upgrade of around 500m of the existing 95mm^2 cable on Gracefield feeder 8 and transfer load from Feeder 2 onto Feeder 8 to address loading on Feeder 2 as explained in section 5.14.2.2 of this chapter.

Upper Hutt Subtransmission protection upgrade – 2015	
Driver: Condition Estimated cost: $350,000 Ref: 15-003	Replace the existing cable differential protection scheme on Maidstone and Brown Owl 33kV feeders with new relays during conversion of the Upper Hutt 33kV bus outdoor to indoor conversion which Transpower has indicated will occur in 2015. Refer to section 5.12.6.

Zone Reinforcement – University / Frederick St / Moore St / The Terrace - 2016	
Driver: Growth Estimated cost: $1-3 million per site Ref: 16-003	Following development of a new CBD zone substation, these substations are expected to require intra-zone reinforcement to provide acceptable security levels within their meshed 11kV ring systems. It may be determined that converting the meshed systems to radial feeders will provide adequate security and reduce the constraints in a more economic way.

Palm Grove 11kV Reinforcement - 2016	
Driver: Growth, Security Estimated cost: $500,000 Ref: 16-001	Installation of a new 11kV feeder into the Palm Grove zone 1 ring to address loading concerns and address potential security of supply issues arising from the high loading in this area as highlighted in section 5.14.2.6.

Wainuiomata Zone Substation 11kV Incomer cables upgrade - 2016	
Driver: Growth Estimated cost: $100,000 Ref: 16-002	Upgrade the existing 11kV incomer cables at Wainuiomata to match transformer and switchgear ratings. These cables are forecast to cause a capacity constraint under N-1 conditions. Refer to section 5.13.9 for details.

New Grenada Zone Substation – 2017/18	
Driver: Growth Estimated cost: $15 million Ref:17-005	Construction of new 20-30 MVA zone substation in Grenada Village north east of Johnsonville. The high load growth north of Johnsonville and in Churton Park area will require new zone substation to meet the future demand. This will offload Johnsonville, Ngauranga and Tawa zone substations, which are expected overloaded by 2016 as explained in section 5.13.3 of this chapter.

CBD Zone Substation Fault Level Improvements - 2017	
Driver: Security Estimated cost: $850,000 Ref: 17-001	To reduce the fault levels at CBD zone substations in order to operate them as closed 11kV bus system. Refer to section 5.13.10 for details.

Land for New Zone Substation in Whitby / Pauatahanui - 2017	
Driver: Growth Estimated cost: $1.0 million Ref:17-004	Land investigation and purchase in the Whitby area for a new zone substation due to load growth in the Whitby and Aotea areas which is steadily increasing the overall demand as highlighted in section 5.13.5. Also more land is being developed for residential housing around Pauatahanui and Plimmerton. Timing of the substation construction is dependant upon load growth and forecasting of when a new zone substation will be required. With present forecasts this is expected around 2017 to 2020, and with a land purchase budgeted for 2017.

University Subtransmission Reinforcement - 2017	
Driver: Growth, Security Estimated cost: $3.5 Million Ref: 17-002	Upgrade of the existing gas filled subtransmission cables into University zone substation as the existing subtransmission capacity does not match the University zone transformer N-1 capacity and has a shortfall of around 4MVA. Replacement of gas filled cables in is line with Wellington Electricity strategy and increases resilience in this area as explained in section 5.13.8.

CBD Zone Substation Fault Level Improvements - 2018	
Driver: Security Estimated cost: $850,000 Ref: 18-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system. The detail of identified issues is provided in section 5.13.10.

Frederick Street Subtransmission Replacement - 2018	
Driver: Growth, Security Estimated cost: $8.5 Million Ref:18-002	Replace the existing Frederick Street gas filled 33kV cables with new high capacity 33kV, XLPE cables. Maximum demand is approximately 99% of N-1 sub transmission capacity and there is limited 11kV interconnection capacity with adjacent substations to allow offloading at peak times, which is further limited due to high demand on neighbouring feeders. This constraint may be alleviated with the construction of a new CBD zone substation in 2015.

5.16.2.1. Prospective Investments for 2019 – 2023

Listed below are prospective projects that may occur in the last five years of the planning period covered by this AMP. These have been budgeted unless otherwise stated, however the timing of the investment may vary depending upon factors such as load growth, technological advances, and whether investments with higher priority are required in this period.

Wainuiomata 33kV Cable Upgrade - 2019	
Driver: Growth Estimated cost: $1.0 million Ref:19-002	33kV cable upgrade at the Gracefield GXP supplying the Wainuiomata overhead 33kV lines to utilise the full rating of the rest of the circuit. There is a small section of underground 33kV cable on Wainuiomata 33kV circuit A which will also be upgraded to match the overhead line and zone substation capacity as detailed in section 5.13.9.

Gracefield Subtransmission protection upgrade - 2019	
Driver: Security, Condition Estimated cost: $500,000 Ref: 19-003	Replace existing protection scheme on eight outgoing 33kV feeders from this GXP with new differential relays to improve security of supply, functionality and performance. Refer to section 5.12.2 for details of existing protection.

CBD Zone Substation Fault Level Improvements - 2019	
Driver: Security Estimated cost: $850,000 Ref: 19-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system.

New Zone Substation in Whitby/Pauatahanui area – 2020/22	
Driver: Security Estimated cost: $15 million Ref: 20-002	Load growth in the Whitby and Aotea areas is steadily increasing, and more land is being developed for residential housing. Existing supplies from Waitangirua are expected to exceed their ratings and provide insufficient security for the increased loads towards the end of the planning period. Development of a substation in this area will also provide increased security to the Mana and Plimmerton areas which are expected to also require reinforcement earlier in the planning period.

CBD Zone Substation Fault Level Improvements - 2020	
Driver: Security Estimated cost: $850,000 Ref: 20-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system.

CBD Zone Substation Fault Level Improvements - 2021	
Driver: Security Estimated cost: $850,000 Ref: 21-001	To reduce the fault levels at CBD zone substation in order to operate them as close 11kV bus system.

Pauatahanui Subtransmission protection upgrade - 2021	
Driver: Security, Condition Estimated cost: $700,000 Ref: 22-002	Replace existing protection relays on the 33kV circuits from this GXP with new differential relays at the time during commissioning of the new subtransmission supply to a new zone substation in Whitby. This work will be undertaken to improve security of supply and improve performance and will occur regardless of whether the proposed substation will be constructed at this time. For details refer to section 5.12.4 of this chapter.

CBD Zone Substation Fault Level Improvements - 2022	
Driver: Security Estimated cost: $850,000 Ref: 22-001	To reduce the fault levels at CBD zone substation in order to operate them as closed 11kV bus system.

5.16.2.2. Capital Expenditure Forecasts

From the details in the section above, Wellington Electricity's network development and growth capital expenditure forecast is shown in the table below. It includes the large projects described as well as expenditure on other growth related capital works such as customer projects and relocations. In comparison to asset renewal expenditure, the expenditure on growth projects is relatively modest, reflecting the low growth rates forecast. Expenditure on other line items generally reflects historic expenditure levels.

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Consumer connection	5,318	6,113	6,380	6,938	7,475	6,925	6,652	7,008	7,153	7,346	8,049
System Growth	3,764	7,994	7,811	7,422	7,924	6,035	5,844	7,095	6,949	6,688	6,373
Asset Relocations	935	935	988	1,095	1,139	1,067	1,056	1,121	1,123	1,136	1,218
Total	**10,017**	**15,042**	**15,179**	**15,455**	**16,538**	**14,027**	**13,552**	**15,224**	**15,225**	**15,170**	**15,640**

Figure 5-59 Capital Expenditure Forecasts – 2013 to 2023 ($000 in constant prices)

From the table above, it can be seen that network development and growth expenditure is cyclic over the planning period. Notable network reinforcement projects are seen around 2013-2017 and 2019-2021 reflective of the prospective need for zone substation development to address network constraints. Customer Connection expenditure is forecast to rise around the middle of the planning period. This reflects the increased development of residential areas as the economy comes out of recession. As existing vacant land is fully developed there will be a corresponding second wave of expenditure in network growth projects.

6. Lifecycle Asset Management

6.1. Asset Lifecycle Planning Criteria and Assumptions

This section provides an overview of Wellington Electricity's asset maintenance, refurbishment and replacement strategies over the planning period. The objective of these asset strategies is to optimise operational expenditure on the network assets whilst ensuring that the network is capable of meeting the consumer service level targets as well as to mitigate the risks inherent in running an electricity distribution network.

Asset lifecycle management consists of the following:

- Routine asset inspections, condition assessments and servicing of in-service assets
- The evaluation of the results in terms of meeting customer service levels, performance expectations and risks
- Adjusting maintenance requirements, and equipment specifications to address known issues
- Repair, refurbishment or replacement of assets when required

The preventative maintenance programme is typically based on a time based cycle, with each asset type, or maintenance task across a group of assets having a set cycle based on a known reliability history or condition degradation trend. Some maintenance activities may have an intervention activity outside the normal time based programme either based on the number of operations undertaken by the asset (e.g. circuit breaker maintenance following fault trips) or based upon external testing results (e.g. tap changer maintenance based on oil tests). All inspections are undertaken on a time based cycle, which may vary for certain assets in each category based upon known issues and risks. In time, as condition assessment data improves for each asset category, planned maintenance cycles for some assets may be able to be extended as the risks associated with the assets may be reduced, conversely, some assets may need a shorter cycle due to their increased risks. Some assets, with a low value, low replacement cost and where the risks of failure are low, may simply be replaced at failure as this is more economically and performance efficient than a full maintenance and refurbishment programme. There are also legislative requirements which require an inspection of assets in the public domain to ensure the pose no unforeseen risk to the public.

Electricity distribution assets do not have an infinite life and must eventually be replaced. Ideally assets should be replaced before they fail. However premature asset replacement is costly since it means that the service potential of the replaced assets is not fully utilised. Hence asset replacement requires the costs of premature replacement to be balanced against the risks of asset failure, public or contractor safety and the deterioration of supply reliability that will occur if assets are allowed to fail in service. There is a balance to be found, between the costs of maintaining an asset against the cost to replace it. Also for some asset types, it may be more cost effective, and have minimal impact on safety and service levels, to allow the asset to run to failure and replace on expiry of service.

Wellington Electricity uses the following criteria to determine whether an in-service asset should be replaced:

- The asset presents an unacceptable risk to the environment or to the safety of public or operating and maintenance personnel.

- The asset condition has deteriorated to the extent that there is a high risk that it will fail if left in service and repair or refurbishment is not practical or economic.
- The asset technology is obsolete and spare parts are no longer available.
- The maintenance cost of the asset over its remaining life in order to sustain existing levels of asset reliability is expected to be higher than the asset replacement cost.
- The asset failure creates a large impact to ongoing customer service or network reliability that would result in a regulatory quality breach or would adversely impact our business reputation.

The remainder of this section focuses on the different asset classes and provides an insight into the condition and maintenance of each class with an overview of the specific asset class, maintenance programs and renewal and refurbishment programmes.

One of the key assumptions Wellington Electricity has based its maintenance and renewal programmes on is that the assets are mature, but are generally in fair condition. This is due to sound maintenance programmes early in their service life and confirmed by further condition assessment activities undertaken in recent years. Improved condition assessment and reporting has enabled Wellington Electricity to gain a better understanding of the network assets and target maintenance and renewal activities on those assets in the worst condition and with the highest risk to the network.

6.2. Stage of Life Analysis

During 2010, Wellington Electricity first undertook a “Stage of Life” analysis on three major asset categories, namely subtransmission cables, zone substation power transformers, and zone substation 11kV switchboards. Each year, the “Stage of Life” analysis is updated with new information gained from inspection and test data, knowledge gained from operating the network for another year, and to reflect the completion of work which addresses age, condition, performance or utilisation of those assets. Details of the outcome of this work are under the respective headings in this section.

The main feature of this analysis is to combine the disciplines of Asset Management with Network Planning to ensure optimal investment on the network. When considered holistically, factors such as age, condition and utilisation can provide an indication of where investment is required based upon total risk to the system. If these factors are considered independently, investment may occur in areas where the risk is not significant (for example an old transformer that has 100% back feed capacity is a lower risk than a better condition transformer where back feeds are not possible or constrained and load may be un-served following a failure).

Each of the factors of age, condition and utilisation are given weightings. The highest weighting is given to utilisation as the consequence of failure is more quantifiable than the likelihood of failure due to age or condition. Ultimately, loading and back feed constraints have a longer term consequence if load cannot be supplied.

These three asset categories (Power Transformers, Subtransmission cables and Zone Substation Switchboards) were selected as they present the highest risk to the system. Also they can be easily considered as discrete assets (compared to asset categories that may have thousands of items) and they represent the areas where investment will be the largest, often millions of dollars per single asset. It is not anticipated that discrete site “Stage of Life” analysis will be undertaken on any other categories. Other categories generally have a lower risk profile and will have renewal programmes driven by type issues, defect and condition information with a view to “whole of life” cost optimisation. There are also network policies created for those assets which include specific elements of “Stage of Life” analysis.

The factors in the “Stage of Life” analysis will change over time as work is completed on the network such as improving capacity or making more spare parts available for older switchboards.

One area to improve in the “Stage of Life” analysis in future is the optimal timing of investment. For some assets this is quite clear from an immediate need due to lack of back feed or exceptionally poor condition. For assets where there is not an immediate need, the use of more complex network investment models decision making tools is required. During 2013 it is planned to commence development of a network lifecycle model which will assist in optimising expenditure against risk of failure and reliability over the asset lifecycle for the network assets as a whole. The results of this will be included in future AMP reports.

The result of the “Stage of Life” analysis for each of the three categories is provided in the relevant section below. The analysis does not aim to provide solutions but rather to identify areas where further investigation is required.

The “Stage of Life” analysis is a constantly changing assessment and needs to be updated on a regular basis, as has occurred in 2012. As the network changes and more or less capacity is available in certain areas, or as asset condition deteriorates or improves, or as spare parts are used up or made available from replacement work, the scores found in the “Stage of Life” analysis will change. As a result, any prospective investment arising from this analysis may vary over the planning period.

6.3. Maintenance Practices

6.3.1. Maintenance Contracts

As noted earlier, Wellington Electricity contracts Northpower as its Field Services Provider to undertake and manage the network maintenance programme under a new Field Services Agreement. At the time of writing this AMP, Northpower are approaching two years of operation on the Wellington network.

The new Field Services Agreement brings a number of improvements to the way maintenance activities are undertaken on the Wellington Electricity network, and how corrective repairs and defects are managed and reported.

The scheduling of inspection and maintenance activities is now driven by Wellington Electricity, based upon the reporting tools available within the maintenance management systems, rather than by the Field Services Provider as it was previously. This arrangement still enables the network owner to receive proposals from the Field Services Provider for further reliability centred investment above the present maintenance expenditure guideline set by the network owner.

The most significant change arising from changing to a new Field Service Agreement in 2011 is a move towards condition based risk management of assets. This is achieved through a well defined condition assessment and defect identification during planned inspection and maintenance activities. When provided back into the maintenance management system by the Field Services Provider and analysed alongside other key network information such as asset nameplate information from GIS and network performance statistics, Wellington Electricity is able to make the most efficient and optimised asset replacement decisions.

There is improved data reporting back to Wellington Electricity for determination and scheduling of maintenance or replacement activities. Combined with database query tools within Wellington Electricity, there is significantly improved visibility and tracking of maintenance tasks and test results received from the field. Further details of the asset management systems and processes are covered in Section 2.8 (Asset Management Systems and Processes).

Vegetation management is provided by Treescape in accordance with Wellington Electricity policies and in accordance with the Hazards from Trees Regulations 2003. Wellington Electricity is nearly at the end of the first cut and trim programme, and in future tree owners will be responsible for maintaining their vegetation to a distance that provides safe clearance of subsequent growth. There is potential that this maintenance may not occur and vegetation related outages may start to increase again if tree owners neglect their obligations under the regulations. Dealing with tree owners who do not take responsibility for their trees competes with the other network maintenance programmes for Wellington Electricity resources.

6.3.2. Maintenance Budget

The maintenance budget is categorised into the following areas:

1. Planned/Preventative Maintenance (PM) works – this PM plan is developed between the maintenance contractor and Wellington Electricity based upon the requirements in the maintenance standards and asset quantities in service. The PM plan consists of routine inspections, as well as maintenance and servicing work undertaken on the network. The results of planned inspections, and also planned maintenance, drive corrective maintenance or renewal activities.

2. Corrective Maintenance works – this work is undertaken in response to defects raised from the planned inspection and maintenance activities, or from observations in the field. The Generally the complete programme is unknown at the beginning of the financial year and budgets are set based on rolling averages from previous years, adjusted (if required) for any known defects beyond what would normally be expected. When common fault modes occur these may be progressed into an asset renewal programme to more efficiently manage the defect.

3. Reactive Maintenance works – this work is undertaken in response to faults or third party incidents and includes equipment replacement and repairs following failure or damage.

4. Management Fee and Value Added – this is to provide for the contractor management overhead and to provide customer services such as cable mark outs, stand over provisions for third party contractors, provision of asset plans for the 'B4U Dig' service etc.

5. Vegetation Management – covering planned and corrective vegetation work undertaken by Treescape.

The maintenance budget costs for 2013 are summarised at the end of this section.

6.3.3. Maintenance Standards

The following maintenance standards are referred to in this section. These standards have been developed by Wellington Electricity from previous network documents and have been rewritten to include new methodologies and requirements. These documents have been reviewed internally and also peer reviewed and benchmarked by senior engineers within other CKI group companies, such as CitiPower and Powercor

Australia. All standards are reviewed by New Zealand industry specialists and benchmarked against current NZ industry best practice.

Standard	Name
EMS-300	Maintenance of Substation Fire Systems
EMS-301	Maintenance of Mineral Insulating Oil
EMS-302	Maintenance of Grid Exit Points
EMS-303	Maintenance of Subtransmission Cables
EMS-304	Maintenance of Zone Substations
EMS-305	Maintenance of Substation Buildings and Enclosures
EMS-306	Maintenance of Zone Substation Transformers
EMS-307	Maintenance of 33kV Bulk Oil Circuit Breakers
EMS-308	Maintenance of 11kV Metalclad Switchboards and Circuit Breakers
EMS-309	Maintenance of Protection Systems
EMS-310	Maintenance of Distribution Substations
EMS-311	Maintenance of Ripple Injection Equipment
EMS-312	Maintenance of Traction DC Systems
EMS-313	Maintenance of Zone Substation Earthing Systems
EMS-314	Maintenance of Batteries and Chargers
EMS-315	Maintenance of Overhead Lines and Components
EMS-316	Maintenance of Fault Passage Indicators
EMS-317	Maintenance of Overhead Switches
EMS-318	Maintenance of Reclosers and Sectionalisers
EMS-319	Maintenance of Distribution Transformers
EMS-320	Maintenance of Distribution Earthing
EMS-321	Inspection and Maintenance of Poles
EMS-322	Maintenance of 11kV Ground Mounted Switchgear
EMS-323	Maintenance of Low Voltage Distribution Equipment
EMS-324	Maintenance of Communications Sites
EMS-325	Planned Maintenance Intervals

Figure 6-1 Maintenance Standards

6.4. Maintenance and Renewal Programmes

This section includes excerpts taken directly from the Preventative Maintenance programme, illustrating the maintenance activities undertaken for particular asset classes and their frequency. Commentary is provided on renewal and refurbishment policies or criteria plus known systematic issues associated with each asset class.

6.4.1. Network Defects Overview

Within the Preventative Maintenance and Inspection programme, and through routine operations, a range of defects are found on network assets. These defects are reported, categorised and remedied according to the nature of the defect, the system level it affects, and the risk it poses to the public, employees and the proper working of the system.

Across the majority of asset categories, the number of reported defects are decreasing each year. This indicates that preventative and corrective maintenance activities are effective and the number of legacy defects are reducing. When compared with network performance detailed in Section 7, the reducing numbers of defects aligns with reductions in equipment related failures in some areas.

Asset Category	Priority Defects			Non Priority Defects			Total
	2011	2012	2013 YTD	2011	2012	2013 YTD	
Battery	0	1	0	0	0	0	1
Circuit Breaker	190	96	14	33	87	0	420
Distribution Substation	1,914	1,220	40	1,836	155	1	5,166
Distribution Transformer	244	415	33	847	178	0	1,717
Grid Exit Point	2	18	1	0	0	0	21
Overhead Line	2	0	0	0	0	0	2
Overhead Switch	11	28	0	48	17	0	104
Pillar / Pit	233	96	3	419	156	0	907
Pole	2,225	1,251	42	893	952	22	5,385
Power Transformer	2	28	1	36	2	0	69
Recloser	0	1	0	1	0	0	2
Ring Main Unit	3	41	6	30	80	0	160
Zone Substation	255	636	8	42	24	1	966
Total	**5,081**	**3,831**	**148**	**4,185**	**1,651**	**24**	**14,920**

Figure 6-2 Summary of Yearly Network Defects

6.4.2. Subtransmission Cables

6.4.2.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on subtransmission cables:

Activity	Description	Frequency
Cable sheath tests	Testing of cable sheath and outer servings, continuity of sheath, cross bonding links and sheath voltage limiters.	2 yearly
Subtransmission - cable gas / oil injection equipment inspection	Inspection and minor maintenance of equipment in substations, kiosks and underground chambers.	6 monthly
Subtransmission - general maintenance, weekly patrol	General maintenance and management of subtransmission network.	Ongoing

Figure 6-3 Inspection and Routine Maintenance Schedule for Subtransmission Cables

In conjunction with the above routine maintenance, all oil filled and pressurised gas cables have pressure continuously monitored via the centralised SCADA system. This monitoring provides information that identifies cables where pressure is reducing and allows the situation to be promptly investigated. Leaks will occur either at joints, which can be rebuilt, or along the length of the cable which makes location and repair significantly more difficult.

One of the key tests is the sheath test, this will indicate where there is damage to the outer sheath and gives an early indication of where corrosion or further damage may occur (leading to leaks), as well as proving the integrity of the earth return path. Most of the subtransmission cables installed on Wellington Electricity's network are three core aluminium or lead sheathed, with very few circuits consisting of single core cables with wire screens.

Subjective condition assessment on cables with oil or gas pressurisation is difficult and quite limited, a number of techniques, including partial discharge testing, are not applicable to these types of cables. By their very nature, the pressurisation of the cables fills any voids in the insulation and prevents partial discharge. The main mode of failure of these cables is stress on the joints and resulting failures, as well as sheath failures allowing gas leaks and areas of low pressurisation along the length of the cable. Leaks are detected through routine operations and the cable can be repaired before the electrical insulation properties are compromised.

The historic fault information for each cable, where known, is used to assess and prioritise the need for cable replacement, as well as determining the strategic spares are required to be held.

6.4.2.2. Cable Condition

<u>Gas filled cables</u>

Gas filled HV cables have been in use internationally since the 1940's and are still in service in many utilities in New Zealand and Australia. They have been proven to perform well when they are installed in benign environments that are not prone to disturbance or damage. Wellington Electricity however has many of its gas filled cables installed under busy roads in urban environments, through structures such as bridges and crossing earthquake fault lines. This therefore requires close monitoring of their performance to manage any deterioration and consequent reduction in levels of service. For example, most of the Evans Bay gas filled cables run under State Highway 1. These cables in particular have been repaired numerous times as a result of third party damage or through gas leaks being found. Vibration from traffic has been identified as a contributing factor to some mechanical failures.

When these cables develop a gas leak, they can usually be dug up and repaired without having to cut the cable. However when a more serious electrical fault occurs, a new section of cable will be necessary. On some occasions a transition joint is employed to join the pressurised gas cables to XLPE cables. These joints are relatively expensive at around $100,000 each and therefore it is not expected that it will be economic to have a large number of such joints in a cable. The likely outcome of this is that economically for any replacement projects, long lengths of cable will be required for replacement rather than for a number of short lengths.

A brief summary of the gas filled cable circuits is listed below:

Circuit	Length (km)[15]	Year installed
Central Park - Evan's Bay	10.1	1958
Central Park - Frederick Street	3.1	1978
Central Park - Hataitai	4.7	1968
Central Park - Palm Grove	5.8	1967
Central Park - University	1.0	1986
Evan's Bay - Ira Street	5.0	1961
Upper Hutt - Maidstone	10.7	1968
Wilton - Karori	7.6	1967
Wilton - Waikowhai Street	3.6	1962

Figure 6-4 Summary of Gas Filled Cable Circuits

The Evan's Bay cables are the oldest on the network and over time they have suffered from a number of leaks which have been repaired. These are however well supported by back-feed options and the load they support is predominantly residential.

A project has been recently completed at the Petone zone substation to provide supply at 11kV from the Korokoro substation. As a result the 33kV cables are no longer the primary supply but remain available for service (N-1 switching) if required as the supply arrangement from Korokoro only provides N security.

[15] Circuit length is the total of all parallel circuits, divide length by number of circuits for route length.

The Johnsonville subtransmission cables experienced a major leak during 2012 which was challenging to locate and repairs were undertaken in three locations. Once the repairs were completed the cable tests were satisfactory and .the residual condition of the cable is good for its age.

Cable Joints

A known issue on some cables installed on steep terrain is where joints expand and contract under cyclic loading, and have been known to pull the conductor from the joint ferrule under contraction. This was experienced in 2010 when one of the old Moore Street gas cable circuits was out of service to enable maintenance by Transpower at the Wilton GXP. The consequence of this was significant given the type of load served (CBD, Government) and the unavailability of the second circuit. These particular cables supplying Moore Street were replaced in 2011.

X-raying of joints was undertaken during United Networks ownership, and little remedial work occurred as the problem had not proved to be significant. This mode of failure is experienced on average every 10 years, with the most recent occurrences being experienced on the old Moore Street cables which have now been replaced.

Cable Strikes

Wellington Electricity, like most lines businesses and other utilities, experiences a number of third party strikes on its underground assets each year. These impact upon network performance, pose a serious risk to health and safety, and incur a large cost to repair. Unfortunately not all of these third party incidents are identified and reported at the time of the incident which may lead to future safety and network reliability problems.

To minimise the number of third party strikes, Wellington Electricity uses a service provider, B4U-DIG, to facilitate the provision of obstruction plans to contractors working in the area, with Northpower providing cable mark outs and standovers where appropriate. Wellington Electricity has targeted contractors working for large utility companies and Territorial Local Authorities (TLAs) with presentations educating them on the importance of cable location and excavation practices. Wellington Electricity is working with the Ministry of Business Innovation and Employment on this matter. This is further discussed in Section 9.6 (Public Safety Management System).

In addition, cable maintenance staff patrol the routes of key subtransmission circuits on a regular basis and note any activities that may impact upon underground services. Where necessary, third party contractors are reminded of the risks associated with working around underground cables.

6.4.2.3. Renewal and Refurbishment

The need for cable replacement is determined and prioritised by a combination of the consequence of a cable failure, condition and performance assessments, analysis of failure and defect rates, and a comparison of the estimated cost of maintaining the cable in service with the cost of replacement, as well as system capacity for supporting load whilst the subtransmission circuit is under repair. These factors are considered in the “Stage of Life” analysis of subtransmission circuits.

Unfortunately for cables there are few cost effective options for refurbishment or extension of life once major leaks, discharge and electrical insulation breakdown has occurred. The solution in most cases is replacement of sections, or the entire length, of cable. Gas and oil filled cable require special transition and stop joints that range in cost from $100,000 upwards each. To relocate, replace sections or extend a cable would cost a minimum of $250,000 using this technology and it is often more economic to replace shorter sections end to end in their entirety.

6.4.2.4. Subtransmission Circuit "Stage of Life" Analysis

During 2012, the "Stage of Life" analysis was updated on all subtransmission circuits, and a summary of the analysis is provided below.

Parameters Considered

The "Stage of Life" analysis method considers the attributes of each subtransmission cable circuit as defined over three categories, each containing a number of measurable properties. A rating between 1 and 10 is given to each property, with 1 being the most favourable (good) and 10 being the least favourable (poor).

Category	Property	Rating (normalised)
Age	Age	1 (good) to 10 (poor)
Condition	Total number of joints	1 (good) to 10 (poor)
Condition	Number of non-original joints	1 (good) to 10 (poor)
Condition	Joint density (Joints / km)	1 (good) to 10 (poor)
Condition	Environment that the cable is installed in	1 (good) to 10 (poor)
Condition	Assessment of cable condition (from field staff)	1 (good) to 10 (poor)
Condition	Assessment of sheath condition (from field staff)	1 (good) to 10 (poor)
Condition	Leakage history (for pressurised cables)	1 (good) to 10 (poor)
Utilisation	N-1 capacity shortfall	1 (good) to 10 (poor)
Utilisation	Residual capacity following transfer of load	1 (good) to 10 (poor)
Utilisation	Type of connected load	1 (good) to 10 (poor)

Figure 6-5 Categories, Properties and Ratings for Subtransmission Circuits

The ratings are normalised over all of the subtransmission circuits so that they can be used as a direct comparison between circuits. Ratings are then weighted as some properties have a greater impact on the stage of life than others.

Category Scores

The weightings allocated to each of the three main categories of age, condition and utilisation are as follows:

Category	Weighting
Age	10%
Condition	40%
Utilisation	50%

Figure 6-6 Category Weightings

The rationale behind these weightings is that age and condition are considered as asset related properties and together they are given equal weighting (i.e. 50%). Utilisation (also 50%) is considered as a planning related property. Age is considered to be less relevant to overall stage of life of the circuit than the condition parameters; hence it is given a rating of 10%, compared to 40% for condition.

Applying the above weightings to the normalised ratings of each category gives the following ranking of circuits requiring attention, ordered with the highest priority circuit (i.e. highest score) at the top of the list.

Zone Substation	Age score	Condition score	Utilisation score	Weighted Total score
Palm Grove	8.2	3.3	7.8	**6.0**
University	4.3	5.0	5.9	**5.4**
Frederick Street	6.2	2.4	7.2	**5.2**
Johnsonville	5.2	5.5	4.8	**5.1**
Evans Bay	10	7.9	1.7	**5.0**
Karori	9.0	4.2	4.7	**4.9**
Maidstone	8.0	5.4	3.8	**4.8**
Tawa	3.9	3.9	5.1	**4.5**
Hataitai	8.0	4.5	3.7	**4.5**
Waterloo	4.7	3.1	5.1	**4.3**
Mana	3.6	3.1	4.9	**4.1**
Ngauranga	3.4	2.0	5.7	**4.0**
Waikowhai	7.8	3.7	3.0	**3.8**
Waitangirua	5.2	3.3	3.8	**3.8**
Korokoro	4.5	3.7	3.4	**3.6**
Plimmerton	3.6	2.1	4.9	**3.6**
Ira Street	9.4	4.3	1.8	**3.6**
Porirua	4.8	1.5	4.4	**3.3**

Zone Substation	Age score	Condition score	Utilisation score	Weighted Total score
Seaview	4.1	1.8	4.2	**3.2**
Wainuiomata	4.1	0.9	4.5	**3.0**
Moore Street	0.0	2.0	4.3	**3.0**
Terrace	0.0	2.1	3.5	**2.6**
Naenae	5.2	1.0	3.2	**2.5**
Trentham	6.0	2.1	2.1	**2.5**
Brown Owl	5.4	1.4	2.6	**2.4**
Gracefield	4.1	0.7	3.3	**2.3**
Kenepuru T off	3.9	1.6	2.4	**2.2**

Figure 6-7 Stage of Life Category Scores for Subtransmission Circuits

Top Ranked Circuits

The top five circuits which have been identified as being most in need of attention are:

Subtransmission link	Ranking (1st = highest priority)
Palm Grove	1st
University	2nd
Frederick Street	3rd
Johnsonville	4th
Evans Bay	5th

Figure 6-8 Stage of Life Ranking of Subtransmission Circuits

Previous "Stage of Life" Analysis outcomes

From the previous "Stage of Life" analysis, major projects were undertaken to address the highest risks on subtransmission network at that time:

1. Frederick Street Load Transfer – installation of 11kV cabling to transfer load from Frederick Street to the adjacent Nairn Street substation to address the security constraints on Frederick Street (N-1 capacity). For the Zone 1 ring, a project has recently been completed to upgrade CB1 from supplying only the local service transformer to a radial feeder to address the concern of increasing load (overloading) and cascading effect during fault.

2. Moore Street subtransmission cable replacement – replacement of the entire double circuit 33kV gas cables from the Wilton GXP to Moore Street zone substation due to condition.

3. Johnsonville reinforcement – Installation of increased 11kV interconnection with Ngauranga zone substation to address the security constraints on Johnsonville (N-1 capacity)

4. Petone 11kV reinforcement – installation of 11kV cable from Korokoro zone substation to Petone zone substation. The 11kV reinforcement project was undertaken to offload Petone zone substation, which is under-utilised, and transfer the load to Korokoro zone substation.

Outcome of the 2012 “Stage of Life” Analysis

Palm Grove

The 2012 study has reinforced the need to replace the 33kV cables with higher rated XLPE cables. This project will start in late 2013 after the completion of the Palm Grove switchboard replacement project, and continue into early 2014.

The Palm Grove subtransmission cables are old but in good condition. The utilisation of the cables is high which has resulted in them being prioritised in the top five circuits needing attention. The maximum demand is approximately 125% of N-1 sub transmission capacity and there is limited 11kV interconnection with adjacent substations to allow offloading at peak times.

A new zone substation proposed for 2015 in the CBD will reduce loadings on inner city zone substations and will reduce the capacity shortfall; however step load changes around Wellington CBD and city areas will see this capacity shortfall return within the planning period.

University

The cable sections of the University subtransmission link are at about mid life and in relatively good condition. Considering they have high joint density and supply the Wellington CBD area, this circuit is given a good rating in both age and condition categories. The loading on the cables and back feed capacity shortfall highlights that the gas cable section of these circuits leads to a constraint. The University subtransmission link also has high numbers of non-original joints (second only to Evans Bay) indicating the potential for significant numbers of cable failures and has recently experienced a high profile cable fault. As a result an investigation is planned in 2013 for its possible upgrading, particularly the replacement of its gas cables.

Frederick Street

Frederick Street has moved into the top five priority list due to high utilisation and limited back feed capacity. This is currently being addressed with a new 11kV feeder project which will add capacity into the 11kV network. A previous 11kV reinforcement project in 2011 has transferred load to the adjacent Nairn Street substation from Frederick Street and has greatly reduced loading, however the loading is still high and forecast to continue growing.

Replacement of the 33kV cables with high capacity XLPE cables will be considered in 2018-2019 following the construction of a new CBD zone substation when final loadings on Frederick Street are known, as the new zone substation may alleviate this constraint or defer the need for investment for some years.

Evans Bay

The Evans Bay subtransmission circuits are old and in poor condition, but are sufficiently lightly loaded that it is still able to provide back feed capacity to adjacent zone substations, and can be back fed with relative ease. There is uncertainty around the developments of the Mt Victoria road tunnel where the cables presently run. No plans to replace the cables will be made until the future developments of the tunnel, and the potential of cost share with the New Zealand Transport Agency NZTA for relocation, are known. The replacement of this circuit is likely to be deferred in favour of a more urgent circuit breaker replacement (to be undertaken in 2013) and power transformer replacement (potentially in 2014), until certainty around the roading changes is known. An investigation into this subtransmission link will be undertaken to identify optimised and appropriate options of investment in the cables.

Johnsonville

Johnsonville is in the top five priority list due to age, high loading and, to a lesser extent, condition issues related to the recent leaks (although now satisfactorily repaired). The loading on these cables will be reduced as a result of the Grenada zone substation construction in 2017 and the residual age and condition factors will be reviewed at that time to determine whether replacement is still justified as a result.

Figure 6.9 provides the project list resulting from the "Stage of Life" analysis which is detailed further in Section 5. These projects are driven predominantly by security and capacity rather than overall condition.

Zone substation	Project Description	Investment year	Driver	Proposed Budget
Palm Grove	Installation of double XLPE 33kV circuit between Central Park and Palm Grove	2013 - 2014	Capacity, Security	$9.0M
University	Replace the gas filled section of University subtransmission circuits with double circuit XLPE 33kV cables	2017	Capacity, Security	$3.5M
Frederick Street	Installation of double XLPE 33kV circuit between Central Park and Frederick Street	2018 - 2019	Capacity, Security	$8.5M

Figure 6-9 Project List for Subtransmission Cables

6.4.3. Substation Buildings and Equipment

6.4.3.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on substation buildings and related equipment:

Activity	Description	Frequency
Zone Substation - Routine Inspection	Routine visual inspection of zone substation to ensure asset integrity, safety and security. Record and report defects, undertake minor repairs as required. Thermal inspection of all equipment, handheld PD and Ultrasonic scan. Inspect and maintain oil containment systems, inspect and test transformer pumps and fans.	3 monthly
Grounds maintenance - Lump sum	General programme of grounds and building maintenance for zone substations	Ongoing
Fire Suppression System Inspection and Maintenance	Inspect, test and maintain fire suppression system (Inergen / gas flood)	3 monthly
Fire Alarm Test	Inspect and test passive fire alarm system	3 monthly
Fire Extinguisher Check	Inspect and change fire extinguishers as required	Annually
Test Zone Substation Earthing system	Test zone substation earthing systems	5 yearly

Figure 6-10 Inspection and Routine Maintenance Schedule for Zone Substations and Equipment

Routine quarterly zone substation inspections include the building and other assets such as lighting, fire systems, security systems, fans, heaters and safety equipment. The grounds and ripple injection spaces are also maintained to ensure access security, condition and safety. Where appropriate, annual building warrant of fitness inspections are carried out and any defects rectified. Building maintenance varies depending upon the site and minor defects are corrected as they are identified.

6.4.3.2. Renewal and Refurbishment

The substation building refurbishment program includes tasks such as roof replacement, exterior and interior painting, security and fencing improvements to maintain the assets in good condition on an as-needed basis.

Given the average age of substation buildings, Wellington Electricity is approaching a period of increased spend to replace doors, roofs and other building components. Deterioration from the natural elements has resulted in maintenance being uneconomic to address weathertightness issues, therefore these components are replaced in entirety. This work is critical to ensure ongoing reliability of electrical plant. Wellington Electricity also considers environmental effects such as heating, cooling and ventilation to ensure network assets are operated within acceptable temperature and humidity levels. Where necessary improvements at substations are undertaken to control the environment in which the plant operates.

Seismic Compliance and Upgrades

In addition to routine maintenance, Territorial Local Authority's (TLA), under their Earthquake Prone Buildings Policy, undertake evaluations of buildings built prior to 1976 which include Wellington Electricity substation buildings. The outcome of the TLA's evaluation process, and Wellington Electricity's independent assessment, may require seismic improvement works on some of these buildings. The TLA allows a period of up to 10 years to reach compliance levels. The scale of the reinforcing works undertaken can differ depending on the independent engineering advice received.

Seismic investigations are also undertaken by Wellington Electricity prior to undertaking any major substation work which may lead to additional seismic strengthening works.

While these seismic projects are essential for the security and safety of the network, they can be costly. During 2012, Wellington Electricity completed and approved its policy on the categorisation, assessment and management of substation building seismic strength and requirements for reinforcing. The revised policy will clarify the business guidance on the risk and importance of each Wellington Electricity owned substation building. The policy will establish the priority of the reinforcement programme of works including capital expenditure forecasting over the planning period.

Seismic reinforcing of substation buildings and how this risk is managed is further discussed in Section 8 (Risk Management).

6.4.4. Zone Substation Transformers and Tap Changers

6.4.4.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on zone substation power transformers:

Activity	Description	Frequency
Transformer oil test (TjH2B TCA)	Sample and test transformer oil using TjH2B TCA (Transformer Condition Assessment) method for power transformer main tank.	Annually
On Load Tap Changer (OLTC) oil test (TjH2B TASA)	Sample and test tap changer oil using TjH2B TASA (Tap Changer Activity Signature Analysis) method for power transformer OLTC.	Annually
Transformer Maintenance, Protection and AVR Test	De-energised transformer maintenance, inspection and testing of transformer, replacement of silica crystals, diagnostic tests as required. Gas injection for testing of buchholz. Testing of temperature gauge and probe. Confirmation of correct alarms. Test AVR and ensure correct operation and indications.	4 yearly
On Load Tap Changer (OLTC) Maintenance	Programmed maintenance of OLTC on a 4 yearly cycle if not maintained before as a result of test.	4 yearly

Figure 6-13 Inspection and Routine Maintenance Schedule for Zone Substations Transformers and Tap Changers

A programme of full oil analysis of all zone substation transformers and tap changers is undertaken by Wellington Electricity on an annual basis. Presently Wellington Electricity uses TjH2b analytical labs for oil analysis. TjH2b undertake a TCA and TASA test to measure dissolved gasses, particles, moisture and furans. These reports return a score of 1 to 4*, with 1 being normal and 4* being worst. Activities such as tap changer maintenance can be programmed based on these results as well as on time or operation based intervals. The TCA result and information in the report can be used to determine whether major maintenance or repairs need to be undertaken on the transformer. In the past two annual tests, only a basic oil dissolved gas analysis was undertaken, however full oil analysis will be undertaken again in 2013 to get full particle, dissolved gas and furan results.

6.4.4.2. Transformer Condition

The condition of all transformers on the network indicates normal performance, with the exception of Wainuiomata and University which are described below. Where evidence of heating or arcing is present, corrective maintenance is undertaken if economic, such as tightening or renewing internal connections outside of the core, or undertaking tap changer maintenance. By far, the most common issue is not electrical performance but rather mechanical problems with transformers. Examples include tap changer mechanism wear, contact wear, and similar problems associated with moving machinery. External condition includes leaking gaskets, fan and cooling system problems and for outdoor installations corrosion and weathering of the transformer tanks, especially the tops where water can pool at times.

Oil tests can also give an estimated Degree of Polymerisation (DP) value that can be used to provide an initial overview of the transformer condition, and signal the need for further maintenance, refurbishment or replacement. Estimated DP tests completed with the DGA oil tests in 2009 (furan analysis) show the majority of transformers to be above 450. It is proposed that once a transformer reaches 300 a paper sample will be taken to prove accuracy of the furan analysis and determine what further steps are required. A profile of estimated DP (as measured in 2009) vs. age, is shown below.

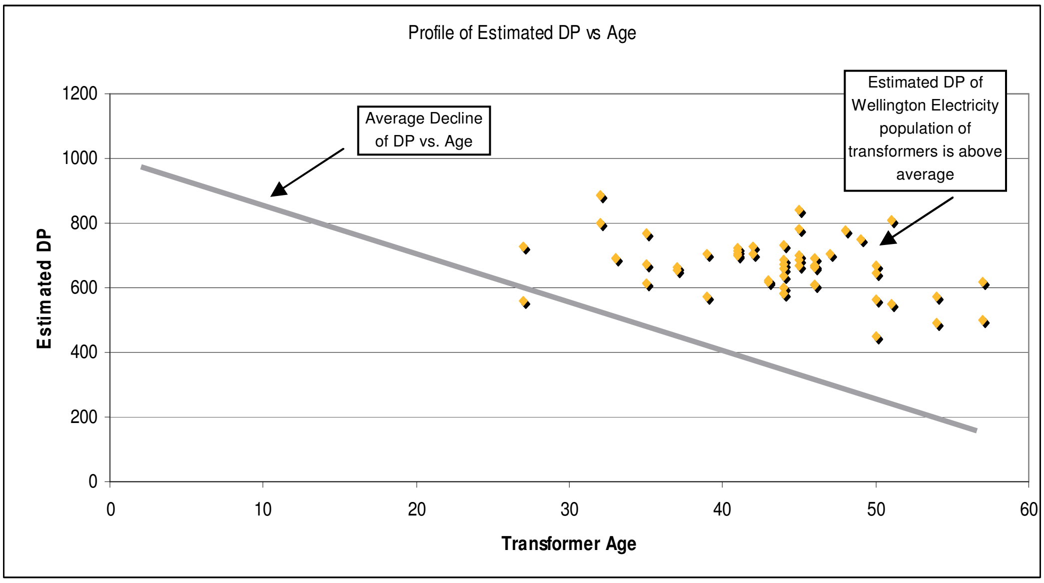

Figure 6-15 Profile of Estimated DP vs. Age (based on 2009 Testing)

From observation of maintenance and testing results, the following site specific issues are known to Wellington Electricity:

Evan's Bay

The transformers installed at Evan's Bay are two of the oldest on the network, having been installed in 1959. These transformers have experienced an increasing number of problems in recent years mostly relating to mechanical performance of the tap changer, and excessive leaks due to deterioration of valves, flanges, gaskets and radiators. Fortunately, corrective works have been possible and the transformers returned to service. The high level of redundancy at this site makes a long duration transformer outage possible with minimal risk to supply. The poor mechanical condition of these transformers indicates they are near the end of their life and major repairs to address the issues are not economic. It is expected that these transformers will be replaced, or have transformers of better condition swapped into this location in the short term.

Ngauranga

Ngauranga has the two oldest power transformers installed in the Wellington Electricity network. These transformers are generally reliable however they have experienced problems with the tap changer diverter switches in the past. These issues will be monitored and corrective repairs undertaken as required. This site has full N-1 capacity at transformer level and can supply the load should one unit be unavailable.

Waikowhai Street

The transformers at Waikowhai Street substation are in good condition. They are however fitted with vertical Reinhausen tap changers which are the only two of this kind on the system. These are more difficult to maintain and are serviced on a 6-8 yearly cycle depending on the results of oil testing. The tap changers were last serviced in 2011 by a Reinhausen technician and it is expected that another 8 years of service can be obtained before major maintenance is required again.

The Terrace

The Terrace substation is located in the basement of the James Cook Hotel in central Wellington. The hotel was built around the zone substation and replacement or removal of a transformer could be challenging in the future. The transformers at this location are carefully monitored to ensure no major issues occur that may lead to removal being required.

Wainuiomata

The Wainuiomata transformers are approaching their end of life. Originally manufactured in 1971, these transformers are installed in an outdoor enclosure exposing the transformers to the environment. The transformers are known to have corrosion and the tanks require refurbishment. Recently transformer A has been identified as having abnormal heating in the windings. Testing indicates that the transformer is suspected to have a core issue. Transformer A is scheduled for oil streamlining and further DGA testing in early 2013, with possible removal and investigation. As an interim risk management plan, one of the power transformers from Petone may be temporarily relocated to this site to maintain full N-1 capacity while transformer A is away for servicing.

University

The University transformers are the two newest power transformers on the network, although manufactured in 1986 and now being at around half-life. The utilisation of the transformers is high and the type of load served (CBD and city fringe) is sensitive to outages. The 2012 annual DGA results indicate that there is abnormal heating in the transformers due to the products identified in the oil samples. It is suspected that oil from the tap changer compartment has made it through to the main tank causing the contamination. Following tap changer maintenance, the oil will be filtered in early 2013 and monitored to determine whether the poor test outcomes were a result of cross contamination or signs of a more serious issue.

Worn Contacts on Tap Changers

An increasingly common problem is worn contacts in tap changers, as previous maintenance practice has been to simply move worn middle contacts to the lesser used top and bottom taps. It is now being found that all contacts are worn and it is costly to replace the entire set of contacts in all tap positions. Each year a number of transformers will have full tap changer contact replacement where the condition is found to be unsatisfactory.

6.4.4.3. Renewal and Refurbishment

Where a transformer is identified for relocation, refurbishment is generally performed if it is economic to do so, based on the condition and residual life of the transformer. A non-invasive test to determine the moisture content of the winding insulation is used to aid the economic decision regarding major transformer refurbishments.

Transformer replacement and life-maintaining refurbishments are prioritised through a combination of invasive and non-invasive tests and inspections to determine the condition of the transformer. Tests are carried out on the oil and winding insulation to provide an indication of probable remaining life of the transformer. Based on this a decision can be made in conjunction with functional, financial and performance requirements of the transformer on whether to retain the transformer in service, to refurbish the transformer or to replace it outright.

The following has been allowed for in the asset maintenance and replacement forecasts for the planning period:

- Transformer replacements at two zone substations
- Ongoing transformer refurbishment costs
- Ongoing preventative maintenance including testing and inspections.

Based on age information, and condition test results, replacement of at least two transformers can be expected to require replacement during the period 2013-2016. The replacement units need not be the oldest nor the worst condition, but where capacity and security constraints indicate a high risk associated with failure. All factors are considered in the replacement decision making which is covered in the “Stage of Life” analysis.

In some instances, where a power transformer is approaching, or at, its service half life, subject to condition assessment results, a refurbishment including mechanical repairs, drying and tightening of the core and associated electrical repairs can be justified. There are 12 transformers that are at a stage where refurbishment is still economic, and some that are showing slight signs of arcing which may require minor refurbishment to check and tighten electrical components. For the majority of the power transformers in the Wellington Electricity network, the testing and inspection programme will aid in getting the best life from the transformer and timing replacement of the unit. This may however not necessarily lead to full refurbishment.

6.4.4.4. Power Transformer “Stage of Life” Analysis

During 2012, the “Stage of Life” analysis was updated for all zone substation transformers and a summary of the analysis is provided below.

Parameters Considered

The "Stage of Life" analysis method considers the attributes of each power transformer as defined over three categories, each containing a number of measurable properties. A rating between one and ten is given to each property, with 1 being the most favourable (good) and 10 being the least favourable (poor).

Category	Property	Rating (normalised)
Age	Age	1 (good) to 10 (poor)
Condition	Estimated Remaining Life	1 (good) to 10 (poor)
Condition	Environmental Protection	1 (good) to 10 (poor)
Condition	Electrical Condition	1 (good) to 10 (poor)
Condition	Assessment of known issues (from field staff)	1 (good) to 10 (poor)
Utilisation	Load vs. Load Rating	1 (good) to 10 (poor)
Utilisation	Type of connected load	1 (good) to 10 (poor)
Utilisation	Number of ICPs served	1 (good) to 10 (poor)
Utilisation	Residual capacity following transfer off-load	1 (good) to 10 (poor)

Figure 6-16 Categories, Properties and Ratings for Power Transformers

The ratings are normalised over all transformers so that they can be used as a direct comparison between transformers. Ratings are then weighted, as some properties have a greater impact on stage of life than others. The properties, along with the ratings and weightings applied to them, are described in detail below.

Category Weightings

The weightings allocated to each of the three main categories of age, condition and utilisation are as follows:

Category	Weighting
Age	20%
Condition	50%
Utilisation	30%

Figure 6-17 Category Weightings

The rationale behind these weightings is that age and condition are considered as asset related properties and together they are given a higher weighting (i.e. 70%). Utilisation (30%) is considered as a planning related property. Age is considered to be less relevant to overall stage of life of the transformer than the condition parameters; hence it is given a rating of 20%, compared to 50% for condition. Condition has been given the highest weighting due to the complex nature of transformers, difficult and costly repairs, and the long lead time for replacement. This differs from subtransmission cables which can be (relatively) easy to repair for isolated condition problems.

Applying the above weightings to the normalised ratings of each category gives the following ranking of transformers requiring attention, ordered with the highest priority transformer (i.e. highest score) at the top of the list.

Transformer	Substation	Age score	Condition score	Utilisation score	Weighted Total score
Evans Bay 1	Evans Bay	9.5	5.0	4.3	5.7
University 1	University	4.7	4.5	8.1	5.6
Palm Grove 1	Palm Grove	8.1	3.1	8.2	5.6
Palm Grove 2	Palm Grove	8.1	3.1	8.2	5.6
Evans Bay 2	Evans Bay	9.5	4.7	4.3	5.5
Ngauranga A	Ngauranga	10.0	3.6	5.3	5.4
Frederick St 2	Frederick St	6.1	3.6	7.7	5.3
University 2	University	4.7	3.8	8.1	5.3
Mana A	Mana	8.8	3.7	5.5	5.3
Terrace 2	Terrace	8.2	2.7	7.5	5.3
Johnsonville B	Johnsonville	7.7	3.5	6.5	5.2
Terrace 1	Terrace	8.4	2.4	7.5	5.1
Porirua B	Porirua	8.1	3.9	5.1	5.1
Porirua A	Porirua	8.1	3.9	5.1	5.1
Wainuiomata A	Wainuiomata	7.4	4.6	4.4	5.1
Johnsonville A	Johnsonville	7.7	3.2	6.5	5.1
Tawa B	Tawa	8.8	3.4	5.3	5.1
Frederick St 1	Frederick St	6.1	3.1	7.7	5.1
Tawa A	Tawa	8.8	3.3	5.3	5.0
Waitangirua A	Waitangirua	8.6	3.6	4.6	4.9
Plimmerton A	Plimmerton	8.8	3.2	5.1	4.9
Waikowhai 1	Waikowhai	8.9	3.3	4.5	4.8
Karori 1	Karori	7.5	3.0	5.9	4.8
Karori 2	Karori	7.5	3.0	5.9	4.8
Maidstone A	Maidstone	7.9	3.8	4.2	4.7
Hataitai 1	Hataitai	7.9	2.8	5.9	4.7
Wainuiomata B	Wainuiomata	7.4	3.8	4.4	4.7
Petone A	Petone	8.1	3.9	3.5	4.6
Ngauranga B	Ngauranga	10.0	2.0	5.3	4.6
Petone B	Petone	8.1	3.8	3.5	4.6

Transformer	Substation	Age score	Condition score	Utilisation score	Weighted Total score
Hataitai 2	Hataitai	7.9	2.4	5.9	4.5
Maidstone B	Maidstone	7.9	3.3	4.2	4.5
Brown Owl A	Brown Owl	7.7	3.5	3.9	4.4
Seaview A	Seaview	7.7	3.2	4.2	4.4
Seaview B	Seaview	7.7	3.1	4.2	4.4
Waterloo A	Waterloo	7.2	2.7	5.3	4.4
Waterloo B	Waterloo	7.2	2.7	5.3	4.4
Waikowhai 2	Waikowhai	8.9	2.3	4.5	4.3
Gracefield B	Gracefield	7.2	3.8	3.2	4.3
Naenae A	Naenae	7.7	3.1	3.9	4.2
Waitangirua B	Waitangirua	8.6	2.2	4.6	4.2
Moore St 1	Moore St	6.8	2.7	4.9	4.2
Trentham B	Trentham	5.8	3.8	3.3	4.1
Brown Owl B	Brown Owl	6.1	3.3	3.8	4.0
Kenepuru B	Kenepuru	7.7	2.8	3.6	4.0
Gracefield A	Gracefield	7.2	3.1	3.2	3.9
Korokoro B	Korokoro	6.5	2.9	3.8	3.9
Kenepuru A	Kenepuru	7.7	2.6	3.6	3.9
Korokoro A	Korokoro	6.5	2.8	3.8	3.9
Trentham A	Trentham	5.8	3.2	3.3	3.8
Moore St 2	Moore St	6.8	1.7	4.9	3.7
Naenae B	Naenae	7.9	1.6	3.9	3.6
8 Ira St 2	8 Ira St	5.5	2.3	3.7	3.4
8 Ira St 1	8 Ira St	5.5	2.0	3.27	3.2

Figure 6-18 Stage of Life Category Scores for Transformers

<u>Top Ranked Circuits</u>

The top five transformers which have been identified as being most in need of attention are:

Transformer	Ranking (1st = highest priority)
Evans Bay 1	1st
University 1	2nd
Palm Grove 1	3rd
Palm Grove 2	4th
Evans Bay 2	5th

Figure 6-19 Stage of Life Ranking of Transformers

Outcome of "Stage of Life" Analysis

Evans Bay

The Evans Bay transformers are old and issues related to their condition have lead to them being ranked in the top five transformers in need of attention. The Evans Bay transformers are proposed for replacement in the short term, potentially in 2014, due to their deteriorating condition. A business case outlining the need for replacement, and detailing the options available, will be prepared during 2013.

The power transformers are leaking oil from cooling fins, glands and flanges and other several places which requires regular inspection and maintenance. The most recent oil tests indicate heating at higher temperature and cellulose degradation maybe occurring which give these units a poor electrical score as well as a poor mechanical condition score.

University

The University transformer 1 has moved into the top five due to current condition of the transformer identified by the most recent DGA results. Though one of the newest power transformers in the network, the utilisation of the transformer is high, which could be a possible cause of the abnormal heating shown in the DGA results (if not tap changer cross contamination). As the key factor is the utilisation issue, a network development solution would be considered rather than an asset renewal. It is likely that the solution to reduce loading will be associated with the construction of a new zone substation in Wellington CBD to reduce loading on this part of the network and provide increased 11kV capacity to meet load growth requirements of University.

Palm Grove

The Palm Grove transformers are old but in good condition. The utilisation score (as a result of the high winter loading) is high which leads to this inclusion in the top five. At this time no investigation or analysis has been carried out for Palm Grove to determine solutions for improving capacity or reducing loading. As it is a utilisation related issue, any solution would be considered a network development project rather than an asset renewal. It is likely that the solution to reduce loading will be associated with the construction of a new zone substation in the Wellington CBD currently programmed for 2015.

Wainuiomata

Although Wainuiomata transformer A did not make the top five of high risk transformers, it is still a concern with its current condition as described earlier in this section. Previously, this site was considered a low priority due to low utilisation and generally acceptable condition. The transformer will be assessed for repairs and refurbished if possible in 2013 to extend its serviceability. It may require replacement in the event it cannot be economically repaired, or the Petone "temporary" transformer may become permanent.

Below is the project list as a result of the "Stage of Life" analysis.

Zone substation	Project Description	Investment year	Driver	Proposed Budget
Evans Bay	Power transformer replacement	2014	Age and Condition	$2.0M
Wainuiomata	Power transformer replacement	2017	Age and Condition	$2.0M

Figure 6-20 Project List for Transformer Replacement

6.4.5. Substation DC Systems

6.4.5.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on substation DC supply systems (battery banks):

Activity	Description	Frequency
Inspection and monitoring of battery & charger condition	Routine visual inspection of batteries, chargers and associated equipment. Voltage check on batteries and charger.	Annually
Comprehensive battery discharge test	Comprehensive battery discharge test for all batteries, measurement and reporting of results.	2 yearly (Zone only)

Figure 6-21 Inspection and Routine Maintenance Schedule for Zone Substation Battery Banks

Valve regulated lead acid (VRLA) batteries are now the only type of battery used. Maintenance is based on the recommendations of IEEE–1188 (IEEE Recommended Practice for Maintenance, Testing and Replacement of Valve Regulated Lead Acid Batteries for Stationary Applications).

6.4.5.2. Battery and Charger Condition

It was discovered in 2009 that a large number of batteries had been allowed to pass their end of service life replacement date. Some batteries had already failed in-service when called upon to operate substation devices during fault or switching conditions. As a result of this discovery, a comprehensive survey of battery installation dates was undertaken and, following replacement where required, there are now no batteries outside the manufacturer's design life. In some installations, where heat is excessive and cannot be controlled, the batteries are replaced earlier than usual due to thermal deterioration. This means that the overall condition of the battery population is now very good.

Battery chargers are also generally in good condition. The majority have SCADA supervision and the Network Control Room can know if the output has failed and initiate a repair. Given the low value and high replacement cost of battery chargers, they are only repaired where it is economic. Generally the chargers are typically at the end of their design life at the time of failure so replacement is readily justified.

6.4.5.3. Battery Replacement

Batteries are replaced using VRLA batteries either as they fail, based on condition assessment results, or when they exceed the manufacturer's design life. For a number of sites, with higher ampere-hour (Ah) demand, 10 year life batteries are available. For smaller sites, or communications batteries where the ampere-hour demand is lower, batteries are only available with 5 year lives. As part of primary plant replacements, Wellington Electricity is intending to standardise the voltages used for switchgear operation as well as communications equipment.

Since 2009, over 500 of the 570 total battery banks have been replaced on the Wellington Network. Going forward all batteries will be replaced every 4-5 years to ensure the standard design life of 5 years is not exceeded. The battery age profile shows major replacement programmes will be required again in 2014 and 2015. To smooth out the more than 400 battery banks for replacement in the next three years, the programme will be staged from 2013 onwards with an average of 150 banks replaced per year.

Replacement Year	Number of Battery Banks	Proposed Budget
2013	150	$150,000
2014	160	$150,000
2015	140	$150,000

Figure 6-23 Annual Battery Bank Replacements

The majority of battery chargers generally have no serviceable parts, maintenance is limited and they are generally replaced upon failure with spares held locally. Some zone substations have an automated battery charger with supervisory monitoring which will alarm in the event of failure.

6.4.6. Switchboards and Circuit Breakers

6.4.6.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on metalclad switchboards and circuit breakers:

Activity	Description	Frequency
General Inspection of 33kV Circuit Breaker	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually

Activity	Description	Frequency
General Inspection of 11kV Circuit Breaker	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
33kV Circuit Breaker Maintenance (Oil)	Maintenance of OCB, drain oil, ensure correct mechanical operation, dress or replace contacts as required, undertake minor repairs, refill with clean oil, return to service. Trip timing test before and after service.	4 yearly
11kV Circuit Breaker Maintenance (Oil)	Withdraw and drain OCB, ensure correct mechanical operation, dress or replace contacts as required, undertake minor repairs, refill with clean oil, return to service. Trip timing test before and after service.	4 yearly (Zone) 5 yearly (Distribution)
11kV Circuit Breaker Maintenance (Vacuum or Gas)	Withdraw CB and maintain carriage and mechanisms as required, record condition of interrupter bottles where possible, clean and return to service. Trip timing test before and after service.	4 yearly (Zone) 5 yearly (Distribution)
11kV Switchboard Major Maintenance (zone)	Full or bus section shutdown, removal of all busbar and chamber access panels, clean and inspect all switchboard fixed portion components, undertake condition and diagnostic tests as required. Maintain VTs and CTs. Return to service.	8 yearly (Zone) 10 yearly (Distribution)
11kV Circuit Breaker - Annual Operational Check	Back feed supply; arrange remote and local operation in conjunction with Network Control Room to ensure correct operation and indication.	Annually (Zone only)
PD Location by External Specialist	External specialist to undertake partial discharge location service, presently HV Diagnostics	Annually (Zone only)

Figure 6-24 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

In addition to the routine maintenance programme above, oil circuit breakers are maintained as required following a number of fault operations.

6.4.6.2. Switchgear Condition

The switchgear installed on the Wellington Electricity network is generally in very good condition overall, with some deterioration on older units. The equipment has been installed indoors and has not been exposed to extreme operating conditions. Historically it has been well maintained which means that whilst the equipment is old, the majority of it is in good condition. In some locations, the type of load served, or the known risks with the type of switchgear mean that an enhanced maintenance programme is required whilst a replacement programme is undertaken, for example Reyrolle Type C and Yorkshire SO-HI switchgear.

Examples of poor condition assessment outcomes include partial discharge (particularly around cast resin components), corrosion and compound leaks visible externally and also arising from service activities, slow or worn mechanisms or unacceptable contact wear. The majority of these observations either do not present a significant risk to the network, or can be easily remedied under Corrective Maintenance programmes.

The condition of zone substation switchboards is considered in the Circuit Breaker "Stage of Life" analysis.

6.4.6.3. Renewal and Refurbishment

Based on the condition assessment carried out as part of the preventative maintenance routine, assets are identified for replacement, or targeted inspection and maintenance programmes to manage risks until replacement is possible. A large number of older circuit breakers remain in place and provide good service as they are in excellent condition due to regular maintenance over the majority of their service life. Some of the older units are showing their age with pitch leaks and failing mechanisms.

Condition, performance, ratings and operational history across the industry are considered when determining the timing for replacement of a circuit breaker. However other drivers that influence the decision for replacement include safety, operability and co-ordination with modern equipment.

Following the implementation of the new planned maintenance programme in 2011, and the resulting improved condition assessment data which has been obtained by late 2012 resulted in sufficient data for compiling longer term renewal programmes by both equipment make and model (type replacement) and also individual units. This is still a work in progress and will be further developed in 2013.

Specific programmes of replacement have been identified for the planning period as follows.

<u>Reyrolle Type C</u>

Reyrolle Type C circuit breakers were installed between 1938 and the late 1960's. Therefore the majority of units have reached the end of their effective service life. There are 57 units remaining in service on the Wellington network which are progressively being replaced, prioritised by condition and location. These circuit breakers need to be inspected for leaks (oil, compound) and thermal imaging and partial discharge inspections are undertaken on an annual basis. This inspection programme ensures defects or potential issues are detected early so corrective actions can be taken. Several units are not able to be operated due to mechanical failure. Replacements are based on the following programme:

Substation	No. of Circuit Breakers	Year installed	Replacement year	Estimated cost
139 Thorndon Quay	5	1954	2013	$ 472,000
Karori Zone	11	1962	2013	$ 1,740,000
Kilbirnie	9	1956	2013	$ 736,000
9 Parkvale Road	9	1964	2013	$ 738,000
Cornwell Street	5	1945	2013	$ 275,000
Gracefield Zone	13	1958	2014	$ 1,850,000
Flag Staff Hill	5	1953	2014	$ 472,000

Figure 6-26 Proposed C-type Circuit Breaker Replacement Programme

After discussion with the Port management, it is proposed that the Cornwell St substation which has old Reyrolle type C switchgear and supplies part of the port area will be decommissioned. The existing load will be transferred to an adjacent substation and the network reconfigured to maintain the same reliability around the network in this area.

Yorkshire SO-HI

Yorkshire SO-HI switchgear was installed during the 1970s and 80s in indoor kiosk type substations and there are approximately 68 units remaining in service. This quantity has increased after previously unknown data in the GIS was updated and revealed three additional SO-HI distribution substation sites. SO-HI switchgear has a history of failing in service and a number of utilities have removed the equipment entirely, or had operational restrictions imposed. The installations in the Wellington Electricity network are in secondary sites.

Wellington Electricity has imposed an operational restriction on these units so they are not operated manually under fault conditions. The constraint has been evaluated against the potential impact on network performance. Wellington Electricity has reviewed all installations of SO-HI switchgear and in 2011 initiated a programme of replacement for switch units, commencing with sites identified as being higher risk (high consequence of failure), with a view to remove the entire population during the planning period. In the past three years, two sites have experienced bus bar flashovers, and one site has had a circuit breaker flashover during circuit breaker installation.

The majority of SO-HI installations do not have protective elements enabled or remote control, and the units can be replaced with conventional ring main units. In a few cases the units have full protection and control, and are located on feeders with high cumulative SAIDI. These will be replaced with modular secondary class circuit breakers.

Replacement solution	No of Sites
Single 3/4 way RMU	12
Duplicate 3/4 way RMUs	4
Circuit Breakers	1

Figure 6-27 Proposed SO-HI Replacement Quantities

The number of sites listed in Figure 6.27 excludes the Todd Motors substation and Pfizer Labs substation which will be decommissioned as the customer opted to have a capacity downgrade. The existing load will be connected to an adjacent substation.

Todd Motors has a large, mostly unused switchboard following the closure of the motor assembly plant. Negotiation will be required with the new site owner to find the best solution for replacement of the switchgear. It is expected a number of ring main units can be deployed around the site to provide supply. The budget for this site is not finalised at this time as it is still in the planning stage.

Priority for replacement will be given to the following sites based upon location, historic SAIDI and customer numbers (potential SAIDI and SAIFI).

New indoor switchgear replacing SO-HI at an indoor substation

Sub No.	Location	Feeder	No. of switches	Customer building	Customers beyond	Replacement year
S1854	453 Hutt Rd	PET 10	5	YES	205	2013
S2413	Nicolaus St	TRE 13	4	NO	645	2013
S1516	Wakefield St A	PET 10	3	NO	272	2013
S2559	Maidstone Mall	MAI 06	3	YES	750	2013
S1075	Queen St (Upper Hutt)	MAI 06	6	YES	836	2013
S2787	Rimutaka Tavern	BRO 10	4	NO	452	2013
S2802	Montgomery Cres A	BRO 10	5	NO	66	2013
S1838	Odeon Theatre #6	MLG 11	3	YES	42	2013
S1800	Levin House	MLG 05	3	YES	63	2013
S3113	Alex Cowans	TAW 6	5	NO	171	2013
S3182	Ceramic Pipes	KEN 1	4	NO	2	2013
S1453	Melbar Engineering	SEA 09	3	YES	44	2013
S1454	CMC	SEA 09	3	NO	44	2014
S1228	7 Waiu St (Feltex)	WNU 03	4	YES	68	2014
S1032	Moera Reserve	SEA 03	4	NO	611	2014
S3289	Ashley's	POR 06	5	YES	22	2014
S3183	Todd Motors	KEN 02	14	YES	10	2014

Figure 6-28 Proposed SO-HI Replacement Priority Sites

Replacement year	No/Type of Sites	Proposed Budget
2013	1CB / 11 RMU	$1,000,000
2014	4 RMU and Todd Motors	$1,000,000

Figure 6-29 Proposed SO-HI Replacement Spend Plan

Statter

There are around 36 known sites with Statter type switchgear on the Wellington network (predominantly in the Hutt Valley area) with around 141 panels in service of both circuit breaker and oil switch type forming a switchboard (making it difficult to separate into distribution switchgear and circuit breaker categories). In recent years there have been instances where the switchgear has failed to operate requiring operating restrictions to be put in place until the unit is repaired or replaced. The Statter switchgear is at the end of useful service life and is becoming difficult to keep in service due to a lack of spares.

The majority of Statter installations do not have protective elements enabled or remote control on the circuit breakers. The units can be replaced with conventional ring main units without causing a decrease of network reliability. In a few cases the units have full protection and control, and are located on feeders with high cumulative SAIDI. These will be replaced with modular secondary class circuit breakers to maintain reliability levels.

With this replacement strategy, the estimated cost of replacing the Statter switchgear is around $3.5M, to be spread over four years with sites replaced on a condition and criticality priority.

Replacement year	No of Sites	Proposed Budget
2013	2 CB / 5 RMU	$700,000
2014	3 CB / 5 RMU	$700,000
2015	3 CB / 4 RMU	$700,000
2016	2 CB / 5 RMU	$700,000
2017	2 CB / 5 RMU	$700,000

Figure 6-30 Proposed Statter Replacement Spend Plan

Reyrolle LMT - Current Transformers (CTs)

Reyrolle LMT circuit breakers were installed on the network from late 1960s onwards. There are over 400 units in service. Partial discharge (PD) testing has indicated potential issues around the current transformers (CTs) / or the CT chamber on units with cast resin CTs. Full partial discharge testing (or handheld TEV testing) and corrective maintenance is undertaken on these circuit breakers when high levels of PD is detected.

Five sets of CTs have been replaced with mixed results. In several cases the PD was reduced to a normal level. In the others there was no change and the cast resin monoblock riser (cable box to CT) is suspected to be a likely contributor to PD levels. Ongoing discussion with the switchgear manufacturer and field investigations lead Wellington Electricity to suspect that the bushing insulator (either of paper or resin) between the CT chamber and the cable box is causing the high PD values. Minor issues such as cable box phase clearances have also been identified as causing high levels of PD.

In the later part of 2012 a circuit breaker at Waitangirua was found to have a high PD value coming from the CT chamber. This prompted a replacement of the CTs, bushings, and pitch-filled cable termination with a new air termination using a retrofit kit developed specially. This significantly lowered the PD to normal levels and confirmed that the retrofit kit is effective in addressing the PD risk on this type of equipment. A corrective refurbishment plan for this type of equipment was developed using this new design.

In 2013, 10 zone substations have been identified for PD correction using this retrofit kit, and one substation (Mana Zone substation) may require additional two retrofit LMVP CB units to replace to replace existing oil CB units which appear to be the source of PD (oil CBs were widely interchanged and CB carriages of differing ages are in service). If successful, this programme will be extended into future years to address this issue.

It has been found that extensions to more recent switchboards have been made using older panels (with SRPB type bushings) which lead to unusual PD results for the age of the switchboard. This practice will now require the replacement of bushings before re-using components.

Replacement year	Number of Sites/CBs	Proposed Budget
2013	10 Sites / 15 panels	$250,000

Figure 6-31 Proposed PD Mitigation Spend Plan

<u>Reyrolle LMT – Rotary Auxiliary Switch Failure</u>

During 2011 a number of instances of circuit breaker “failure to operate” occurred under fault and switching operations. This was identified as being a result of contamination of the rotary auxiliary switch leading to false indications and also preventing operation due to the interlocking status being incorrect.

A sample of the contaminant was analysed and found to contain high levels of a styrene residue on the contacts, as well as oil and grime. Although no cause can be known as certain, it is suspected previous maintenance practices have introduced solvents which have released the glues and plastics inside the switch body. These have has migrated onto the contacts and act as an insulator, leading to the “failure to operate” issues.

The correct maintenance practices have been reinforced with the Field Services Provider, including corrective actions where a faulty unit is found. Dust covers are fitted to cleaned contacts to prevent dust and grime ingress. The switchgear manufacturer has started providing factory made dust covers for new circuit breakers of this type supplied to the network.

From the introduction of dust covers and the corrective maintenance regime to clean the contacts, reports of “failure to operate” on LMT type CBs have been reduced. This outcome is expected to be further proven when all the LMT CBs are maintained and installed with dust covers on the auxiliary switches.

6.4.6.4. Circuit Breaker “Stage of Life” Analysis

During 2012, the “Stage of Life” analysis was updated on all zone substation 11kV switchboards, and a summary of the analysis is provided below.

Parameters Considered

The "Stage of Life" analysis method considers the attributes of each switchboard as defined over three categories, each containing a number of measurable properties. A rating between 1 and 10 is given to each property, with 1 being the most favourable (good) and 10 being the least favourable (poor).

Category	Property	Rating (normalised)
Construction	Age	1 (good) to 10 (poor)
Construction	Number of Circuit Breakers	1 (good) to 10 (poor)
Condition	Partial Discharge Testing Results	1 (good) to 10 (poor)
Condition	Internal Condition assessment	1 (good) to 10 (poor)
Condition	Spares availability	1 (good) to 10 (poor)
Utilisation	Loading vs. load rating	1 (good) to 10 (poor)
Utilisation	Fault level vs. fault rating	1 (good) to 10 (poor)
Utilisation	Type of load served	1 (good) to 10 (poor)
Utilisation	Number of ICPs served	1 (good) to 10 (poor)
Utilisation	11kV back feed capacity	1 (good) to 10 (poor)

Figure 6-32 Categories, Properties and Ratings for Switchboards

The ratings are normalised over all of the switchboards so that they can be used as a direct comparison. Ratings are also weighted as some properties have a greater impact on stage of life than others. The properties along with the ratings and weightings applied are described in detail below.

Category Weightings

The weightings allocated to each of the three main categories of construction, condition and utilisation is as follows:

Category	Weighting
Construction	20%
Condition	20%
Utilisation	60%

Figure 6-33 Category Weightings

The categories have been given these weightings on the basis that utilisation, in particular, will be one of the main drivers for remedial action to be taken on a switchboard. Wellington Electricity cannot operate equipment outside its ratings, or have underrated equipment that will affect the proper working of the system.

Construction and condition have equal weightings of 20% each, as neither by itself would be a major driver for remedial attention. Wellington Electricity has a number of medium sized switchboards in service in distribution substations that are over 60 years old. Minor defects or deteriorating condition alone can generally be resolved by partial replacement or increased levels of corrective maintenance. However when combined with high utilisation scores, construction and condition become more important in determining risks associated with each switchboard.

Applying these weightings to the normalised scores from each category allows an overall score to be derived for each switchboard, in turn giving a priority ranking.

Substation name	Switchboard type	Construction score	Condition score	Utilisation score	Total score
Frederick Street	LM23T	7.9	5.8	9.1	8.2
Karori	C	9.1	5.6	7.4	7.4
University	LMT	6.1	4.8	8.6	7.3
Moore St	LM23T	9.1	4.8	7.2	7.1
Hataitai	LM23T	9.0	3.8	7.6	7.1
Nairn Street	LMT	7.6	4.8	7.3	6.8
Kaiwharawhara	LMVP	5.3	1.8	8.9	6.7
Johnsonville	LM23T	9.1	3.8	6.9	6.7
Porirua	LM23T	9.3	4.8	6.1	6.5
Tawa	LM23T	9.3	5.8	5.7	6.4
Gracefield	C	9.4	5.6	5.6	6.4
Waterloo	LMT	8.5	2.8	6.8	6.4
Ira St	LM23T	8.5	3.8	6.3	6.3
Waikowhai	LMT	8.8	1.8	6.3	5.9
Waitangirua	LM23T	9.3	4.8	5.1	5.9
Brown Owl	LM23T	9.1	3.8	5.5	5.9
Seaview	LM23T	9.4	2.8	5.6	5.8
Naenae	LM23T	9.4	2.8	5.5	5.8
Maidstone	LM23T	9.4	3.8	5.0	5.7
Wainuiomata	LMT	8.7	2.8	5.6	5.6
Petone	LM23T	9.1	2.8	5.3	5.6
Kenepuru	LM23T	8.8	3.8	5.0	5.5
Terrace	NX-PLUS	3.4	2.0	7.3	5.5
Mana	LM23T	6.7	4.8	5.0	5.3
Trentham	LM23T	9.4	3.8	4.3	5.2
Korokoro	LM23T	8.6	3.8	4.5	5.2

Substation name	Switchboard type	Construction score	Condition score	Utilisation score	Total score
Plimmerton	LM23T	7.9	3.8	4.5	5.0
Ngauranga	LMT	4.7	4.8	5.0	4.9
Titahi Bay	LMT	8.5	4.8	3.7	4.9
Palm Grove	LMVP	1.8	0.0	7.4	4.8
Evans Bay	LMVP	1.6	0.0	6.2	4.0

Figure 6-34 Stage of Life Category Scores for Switchboards

The analysis considered Palm Grove and Evans Bay as already replaced with new switchboards which will be complete at the time this AMP is published.

Top ranked switchboards

The top five ranked switchboards which have been identified as being in need of attention are:

Switchboard	Ranking (1st = highest priority)
Frederick Street	1st
Karori	2nd
University	3rd
Moore Street	4th
Hataitai	5th

Figure 6-35 Stage of Life Ranking of Zone Substation Switchboards

Previous "Stage of Life" Analysis outcomes

From the previous "Stage of Life" analysis on zone substation switchboards, a major project was undertaken to address two of the highest risk switchboards on network at that time:

1. Palm Grove zone substation switchboard replacement – this Reyrolle Type C switchboard was approved for replacement based upon the age and high utilisation (over 9,000 ICPs and exceeding the N-1 incomer rating).

2. Evans Bay zone substation switchboard replacement – this Reyrolle Type C switchboard was approved for replacement based upon the age and high utilisation (over 5,000 ICPs and with poor mechanical condition).

Outcome of 2012 "Stage of Life" Analysis

Frederick Street

Frederick Street features highly in this analysis as a result of its utilisation score. It has a loading of over 30MVA and supplies over 10,000 consumers in the CBD area. Being a CBD substation, the bus is operated split, reducing the prospective fault level. However under some switching conditions it is likely to exceed its fault rating. It is generally in sound condition, apart from some identified partial discharge activity around the CTs which will be resolved under the PD correction programme in 2013. This switchboard features highly due to the consequence of failure related to the size and type of load served.

This switchboard may be a suitable candidate for a retrofit upgrade using new components from RPS Switchgear to improve load and fault ratings. Early LM23T boards such as this have been re-rated by the manufacturer to 25kA based upon the fixed portion design (the busbars, CTs and other components not including the circuit breaker units which are withdrawable). The replacement of oil circuit breaker carriages is required to achieve this rating, and new blast protection panels provide improved safety. At Frederick Street specifically, the installation of vacuum circuit breakers, improved protection with arc-flash detection, and replacement of the double 1200A incomer arrangement with single 2000A incomers will see the rating issue reduced.

The Frederick Street 11kV reinforcement project recently completed has moved some load away from this site. While improving its utilisation score as the loading is reduced, the residual utilisation is still high. Further analysis of the loading issue is found in Section 5 (Service Levels).

Karori

The Karori switchboard was installed in 1963 and is past the end of its technical life. The condition score is moderate as it has limited spares and a history of mechanical faults and poor tests (although somewhat less than the similar aged switchboard at Gracefield). The utilisation score is high as the fault level is over the fault rating of the switchgear, though the number of ICPs and the type of load served is moderate.

This switchboard is next for replacement following Palm Grove and Evans Bay, due to age and utilisation and will commence in late 2013.

University

University has relatively modern switchgear compared to the majority of Wellington Electricity zone substations, having been installed in 1988. The utilisation factor on this substation is the main reason it is included in the top five list. The substation has a fault level under closed bus situations that exceeds the fault rating of the switchgear, as well as supplying CBD load. The loading level is moderate.

This substation does not need switchgear replacement at the present time as the age and condition is good, however operational restrictions regarding the closed bus need to be observed. This is achieved through NCR operating procedures to minimise the time the two supply transformers are paralleled. Following the evaluation of retrofit upgrades and re-rating at Frederick Street this solution may be able to be applied to University to improve fault ratings.

Moore Street

Moore Street scores highly due to both its construction (age, and number of circuit breakers), as well as its utilisation, as it supplies CBD load, is heavily loaded and has inadequate fault rating under closed bus operation. The issues are currently being managed through operational procedures. The condition score is low, therefore indicating few issues with the switchgear given its age.

A number of options exist for Moore Street, however as it is ranked fourth, investigation work at other substations, particularly around re-rating the fault level may allow an alternative to replacement at this site.

Hataitai

Hataitai moves up the priority ranking after upgrading of the Palm Grove switchboard. It is one of the oldest on the network and is Reyrolle Type LM23T switchgear. Hataitai scores highly on both construction and utilisation scores, as it is at the end of its technical life and has inadequate fault rating for closed bus operation. There are adequate spares available and no major or reoccurring issues have been identified with this switchboard.

Given the age of the equipment and limited ratings, while this switchboard is still a suitable candidate for replacement it will be further investigated in 2013. This switchboard is older than similar boards at University, Frederick Street and Moore Street.

Gracefield

From the stage of life analysis, Gracefield zone substation is outside the top five highest priority ranking due to its lower utilisation and the assessed lower consequence of failure. Gracefield though is the last zone substation site with Reyrolle type C switchgear and it is scheduled for replacement in 2014. This replacement is driven by strategic alignment with the plan to remove all Reyrolle C gear from service on the network.

Palm Grove 11kV switchboard following replacement

6.4.7. Substation Protection Relays

6.4.7.1. Maintenance Activities

The following routine planned testing and maintenance activities are undertaken on protection relays:

Activity	Description	Frequency
Protection Testing for Electromechanical Relays	Visual inspection and testing of relay using secondary injection. Confirm as tested settings against expected settings. Update of test record and results into Protection Database	2 yearly (Zone) 5 yearly (Distribution)
Protection Testing for Numerical Relays	Visual inspection, clearing of local indications, and testing of relay using secondary injection. Confirm as tested settings against expected settings. Confirm correct operation of logic and inter-trip functions. Update of test record and results into Protection Database	2 yearly (Zone) 5 yearly (Distribution)
Numerical Relay Battery Replacement	Replacement of backup battery in numeric relay	2 yearly (Zone) 5 yearly (Distribution)

Figure 6-36 Inspection and Routine Maintenance Schedule for Zone Substation Protection Relays

Regular testing of protection relays is undertaken to determine correct operating functionality. Protection relay testing will continue on a regular basis and budgetary provision for this has been made in the maintenance expenditure projections.

The key focus of protection relay maintenance is to identify any equipment that is not operating correctly or has failed. In order to maintain network reliability performance it is necessary to identify these issues before a failed or mal-operating protection relay is required to operate. This is especially relevant with the large number of older electromechanical relays on the network.

Testing of the large number of differential relays on the network (Reyrolle SOLKOR, or similar) also serves to test the copper pilot cables between substations. Upon a failed test, the protection circuit is either moved to “healthy” pairs on the pilot cable, or the cable is physically repaired. Due to deteriorating outer sheaths on pilot cables, some early pilot cables are now suffering from moisture ingress and subsequent degradation of insulation quality. A grease filled pilot joint is now being used to block moisture from spreading though entire sections of cable.

Numerical relays, although equipped with self-diagnostic functions, are tested as shown in the table above. With more complex protection schemes coming into service, these need to be tested to ensure the correct functions and logic schemes are still operating as expected.

6.4.7.2. Renewal and Replacement

The majority of electromechanical relays are approaching the end of their technical life. However the economic impact of replacement with modern numerical protection relay equivalents is being carefully considered. Therefore, the replacement programmes that are in place generally focus on relay condition and coordination with other replacement programmes or projects especially for assets such as switchgear and transformers. Rarely does a relay fail in-service and deterioration of relays is picked up during routine maintenance testing which may lead to individual replacement.

At the time of primary equipment replacement the opportunity is taken to upgrade associated protection schemes to meet the current standards because the relays are usually mounted within switchgear panels as an integral system. To date, electromechanical relays have provided reliable service and are expected to remain in service for the life of the switchgear it controls – generally greater than 40 years. For newer numeric relays, it is not expected that the relay will provide the same length of service and a service life of less than the ODV standard life is expected.

The following programmes and projects have been allowed in the asset replacement and maintenance budgets.

- Ongoing replacement of PBO relays in conjunction with switchgear replacements in the short term, or individually where known risks exist. Sites with PBO relays will be identified in the maintenance programme over the next two years, and any replacement programme determined from then.
- There are around 10 Nilstat relays still in service which will need to be replaced, however they are in a Reyrolle Type C switchboard, so total replacement will occur in the short term as the last switchboard is scheduled for replacement in 2014 and an individual replacement project is not justified.
- Ongoing zone substation and network protection and control replacement/upgrades for assets supplied from GXPs, particularly Takapu Rd, Haywards, Gracefield, Upper Hutt and Wilton as part of upgrades Transpower will undertake.
- Ongoing protection and control replacements/upgrades across the network as identified by asset condition monitoring.

6.4.8. Load Control Equipment

6.4.8.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on load control equipment. Wellington Electricity owns the injection plants located at substations and blocking cells at GXPs, but not any of the consumer receivers. As such the full end to end testing of the ripple system is not possible.

Activity	Description	Frequency
General Inspection	Check output signal, visual inspection, thermal image and partial discharge scan, motor generator test run	6 monthly
Maintain Ripple Injection Plant	Clean and inspect all equipment, maintain motor generator sets, coupling cell test and inspection	Annually
Blocking Cell Testing and Maintenance	Visual inspection, cleaning and maintenance of ripple blocking cells at GXPs as required	5 yearly

Figure 6-37 Inspection and Routine Maintenance Schedule for Ripple Plant

6.4.8.2. Renewal and Refurbishment

Wellington Electricity has no short terms plans to replace any ripple injection plant due to age or condition. Repairs and maintenance are undertaken as required, and the plant is generally reliable. Basic spares are held locally, and other items can be sourced from abroad as required, but with longer lead times.

In the Hutt Valley area, interconnectivity at 11kV allows ripple signal to be provided from adjacent substations in the event of failure. In the Wellington city area, there is dual plant located to supply each of the GXPs at 33kV, with two 11kV plants supplying the Kaiwharawhara 11kV point of supply.

As risk mitigation for the Wellington City area, a spare ripple converter unit was purchased in 2011 to be able to connect to any of the four city ripple injection locations in the event of a failure of the existing plant. The primary risk was the failure of one of the two converter units at Frederick Street as the remaining unit would not be large enough to provide adequate signal for all network configurations.

In the medium term, Wellington Electricity will look to replace older rotary plant installed on the 11kV system in the Hutt Valley and Porirua areas as these assets are approaching the end of their service life. It is likely that replacement may involve rationalisation of plant by installing larger plant at GXP level, using modern low frequency ripple signals, rather than high frequency injection at Zone Substation level. Whilst technically straightforward it may become a complex issue involving retailers and meter/relay asset owners.

The ripple control injection plant for the Central Park GXP area is a Brown-Boveri plant located at the Frederick Street zone substation and comprises two units operated in parallel. With one unit out of service, ripple signal strength is marginal in some parts of the network. This matter has been investigated and it is related to the increased load on the Central Park 33kV bus following the reconfiguration of supply to The Terrace substation from Central Park (previously from Wilton GXP), and the moving of the Central Park 11kV point of supply (Nairn St substation) transformers from the 110kV bus to the 33kV bus. The installation of a larger plant connected to the Central Park 33kV bus is not necessarily the best option. A move to a modern low frequency plant (resulting in better signal propagation) would involve changing adjacent GXPs to the same frequency to ensure ripple control is available under any supply configuration. The overall solution for this area is still being developed, although it is expected that investment will be required within the planning period.

There are some small areas of network that receive DC bias load control signals. This system is no longer supported and it is unknown how many consumer installations still use the DC bias system. It is proposed to decommission this system in the short term as projects allow the removal of the DC bias injection plant (typically located at distribution substations). Affected consumers will be moved to ripple load control. The process required, and the implications both in terms of technical and commercial arrangements, need to be fully worked through as this affects the incumbent metering owner's receiver assets.

In 2012, the Takapu Road capacitors were found to be in need of replacement, and a similar set at Melling were found to be in poor condition requiring refurbishment. Maintenance requirements for these units are being worked through with the maintenance provider. The blocking cells at Gracefield were refurbished in 2012 and early 2013 after a failure due to corrosion issues. Following refurbishment, these units have a reasonable remaining service life.

Investment in ripple load control plant is largely on hold at present due to the uncertainty around load control as detailed earlier in this plan.

6.4.9. Poles and Overhead Lines

6.4.9.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on poles and overhead lines:

Activity	Description	Frequency
Inspection and condition assessment overhead lines by zone/feeder	Visual inspection of all overhead equipment including poles, stay wires, crossarms, insulators, jumpers and connectors, switchgear and transformers. All HV and LV circuits by feeder. Recording and reporting, and minor repairs as required.	Annually
Concrete and steel pole inspections and testing	Visual inspection of pole, tagging and reporting of results.	5 yearly
Wooden pole inspections and testing (Deuar)	Visual inspection of pole, testing and analysis of pole using Deuar MPT40 test, tagging and reporting of results.	5 yearly
LFI inspections	Visual inspection of line fault passage indicator, testing in accordance with manufacturer recommendation.	Annually
LFI battery replacement	Removal of unit, assessment of condition and replacement of onboard battery, replacement onto live line using hot stick.	8 yearly

Figure 6-38 Inspection and Routine Maintenance Schedule for Poles and Overhead Lines

All overhead lines are programmed for an annual, visual inspection to determine any immediately obvious issues with the lines, condition of components such as crossarms and insulators, and to note any prospective vegetation, third party encroachments or safety issues. In addition, all connectors in the current carrying path get a thermal scan to identify any high resistance joints which may fail due to heating. These inspections drive a large part of the overhead corrective maintenance works, as well as contribute to asset replacement programmes for insulators and crossarms.

Soon after taking ownership of the network Wellington Electricity undertook a review of pole testing methods. It was concluded that the Deuar MPT40 best satisfies the need for objectivity, repeatability and accuracy. This conclusion is supported by independent analysis and referees.

The Deuar testing programme commenced in the third quarter of 2011 and has so far has been effective, with the number of condemned poles being at expected levels. The programme also addresses concerns that the previous method was not picking up structural issues deeper at the base of the pole, and provides useful remaining life indicators. The efficiency of the programme is improving as operators become more familiar with the testing techniques.

Around 3,000 poles have been tested since the start of the Deuar testing program. From this testing programme, a substantial number of very old poles have been given a serviceability extension, whereas others have been identified for replacement early in their life due to serviceability based upon the pole loading.

6.4.9.2. Pole Condition

The majority of poles on the Wellington Electricity network are generally in good condition as a result of a large scale testing and replacement programme which occurred between 2004 and 2006. Over two thirds of the poles installed in the Wellington region are concrete, which are durable and in good condition. The remainder are timber poles which are tested and replaced in accordance with their serviceability index result or where there are visible structural defects. A number of older hardwood poles have been reclassified as Wellington Electricity owned following a pole survey in 2009 and are now subject to a test regime which is presenting a higher than typical failure rate, however this is likely due to not having been part of a programmed test regime over the past decade.

Common condition issues with timber poles are deterioration of pole strength, either through internal or external decay. Poles can also be found to be leaning, having head splits or incurring third party damage which may necessitate pole remediation or replacement.

Common condition issues with concrete poles include cracks, spalling (loss of concrete mass due to corrosion of the reinforcing steel), leaning poles and third party damage.

A significant contributor to leaning poles on the Wellington network is third party attachments. There are existing agreements to support telecommunications cables from TelstraClear and Telecom on network poles, and in some areas the additional loading exceeds the designed foundation strength leading to leaning of poles across the network. Many of these can be remedied with corrective maintenance to straighten the pole and improve the foundation design through blocking or compacting course metal around the pole base.

Wellington Electricity is in the process of finalising a standard for third party attachments to network poles. This standard is aimed to ensure future connections to poles for telecommunications infrastructure (for example) meet Wellington Electricity’s requirements and do not have an injurious effect on the network. It is expected that third party network operators will be required to contribute to the upgrade of network poles where there will be an impact on pole service life or safe working load as a result of additional infrastructure connections.

Pole Testing using the Deuar MPT40 test method

6.4.9.3. Overhead Line Condition

Pin type insulators are no longer used for new 33 kV or 11 kV line construction as they develop reliability issues later in life such as split insulators due to pin corrosion, and also leaning on crossarms due to the bending moment on the pin causing the crossarm hole to wear out. There is no programme to proactively replace existing pin type insulators. This will occur under system maintenance when defects are identified or when crossarms require replacement. All new insulators are of the solid core post type as do not suffer the same modes of failure that pin insulators do, and they provide a higher level of reliability in polluted environments and lightning prone areas than the pin type insulators historically used on the network.

High wind loadings can sometimes result in fatigue failures around line hardware such as binders, compression sleeves, line guards and armour rods on the older All Aluminium Conductor (AAC) lines that have historically been used on the Wellington network. Recent incidents have also shown fatigue problems with fittings supporting strain points. Conductor fatigue issues such as these cannot be visually detected, therefore it is proposed to take a sample of conductor and components from service and have these analysed by materials scientists to determine remaining asset life in order to plan for a proactive replacement program. Where a conductor issue is identified, All Aluminium Alloy Conductor (AAAC) will be used as a replacement material due to its increased strength and improved fatigue resistance.

It should be noted that steel reinforced conductors have not been widely used in the Wellington region due to high salt pollution causing shortened service life from corrosion of the steel core.

It has been observed that a number of Fargo sleeve type automatic line splices were failing in service. These sleeves are only suitable for a temporary repair and in some cases had been in service for over 10 years. The failure mode for Fargo sleeves is likely to be vibration related and can cause lines to fall and result in feeder faults. Fargo sleeves are no longer used on the network and when found they are given a defect rating for replacement. Replacement will be with full tension compression sleeves or the span will be re-conductored if the replacement joints are not suitably located.

6.4.9.4. Renewal and Refurbishment - Lines

Since 2009, Wellington Electricity has invested in renewal of overhead lines in areas which were found to have particularly high SAIDI and SAIFI, or to address public safety concerns. Areas of Newlands (Ngauranga 4 Feeder) and Korokoro have now been reconductored, and have had all the line hardware, crossarms and poor condition poles replaced. These two feeders have had a significant improvement in performance since this work was completed. Another section of the Ngauranga 4 feeder was rebuilt and reconductored in 2012 which has significantly improved performance of this feeder.

Two of the worst performing feeders in 2012 were Wainuiomata 7 and Karori 2 are being refurbished over a 10 year period (to 2022) due to the long rural nature of these. Both feeders will have Stage 2 of their renewal programme undertaken in 2013. A section of Ngauranga 9 will also be refurbished in 2013 to address concerns around Newlands and Paparangi.

It is likely that similar reconductoring or area rebuild projects will occur as further issues arise on the network, or where there are increased instances of conductor or component failure. This work usually involves sections of line of only a few hundred metres up to several kilometres. Details of prospective overhead network renewal and refurbishment projects are covered later in this section under Feeder Performance.

6.4.9.5. Renewal and Refurbishment - Poles

Following inspection of poles, and failing the serviceability test, they are categorised as red tagged, or yellow tagged. Red tagged poles have a serviceability index of less than 0.5 (to allow for a design safety factor of two) or have a major structural defect, and are programmed for immediate replacement (3 months). Yellow tagged poles have a serviceability index of 0.5 to 1.0, or have moderate structural defects, and are programmed for replacement within 12 months. Crossarms are identified for replacement from the detailed line inspections.

With the introduction of the Deuar pole testing methodology, it is expected that a higher accuracy of assessment of pole strength and remaining life will occur. As a result pole replacements will decrease over time and poles that are replaced are the most “at-risk” on the network. Initial testing with the Deuar programme has produced similar replacement rates as previous methods, however many of the poles in the initial testing programme were prioritised as those with known low strength but were still serviceable at the time of the last test.

The Deuar testing results have come up with a large number of poles, which would be considered to be at the end of life, given an extension of serviceability of more than 10 years, and some for over 50 years. Initial testing using this method has returned higher than expected rates of failure, however Wellington Electricity has been targeting areas with unknown test histories and with tests more than six years old, so an initial high rate of failure is understandable.

Steel and composite poles are being reviewed for use on the Wellington Electricity network as a possible replacement for softwood poles. Poles on walkways and hard to reach areas are normally replaced with light softwood poles because they can be carried in by hand. However these are considered to be a poor choice of pole as they are often of varying strength and have poor service life (typically no longer than 25 years). Wellington Electricity does not consider the use of helicopters in erecting concrete poles in such areas viable due to the cost and the need to evacuate residents around the pole location. Cranes are used where practicable but have limited reach in some areas of Wellington.

Concrete poles are replaced following an unsatisfactory visual inspection, with large cracks, structural defects, spalling or loss of concrete mass being the main criteria. All replacement poles are concrete, except where the location requires the use of timber for weight, access constraints or loading design.

It is expected that if a third party user of the poles wishes to extend their existing network or use Wellington Electricity's overhead network as a carrier, such as a telecommunications company stringing aerial fibre optic cables, an assessment of existing poles will be required. Pole replacement will need to occur where design strength parameters are exceeded or height clearance issues are encountered either on a cost share or causer pays basis.

Figure 6.40 provides a yearly overview of inspection and replacement of poles.

Year	Inspected		Replaced	
	Wood	Concrete	Wood	Concrete
2010	1,094	35	316	33
2011	775	6,656	325	18
2012	2,816	4,995	306	51

Figure 6-40 Yearly Pole Inspection and Replacement

Pole inspection and replacement was at a low level for the 2010-2011 period with programmes of replacement commencing again following the testing method review in 2011.

6.4.10. Overhead Switches, Links and Fuses

6.4.10.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on overhead switches, links and fuses:

Activity	Description	Frequency
Visual Inspection and Thermal Image	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections.	Annually
ABS Service	Maintain air break switch, clean and adjust contacts, check correct operation.	3 yearly
HV Knife Link Service	Maintain knife links, clean and adjust contacts, check correct operation.	3 yearly
Gas Switch Service	Maintain gas switch, check and adjust mechanism as required.	9 yearly

Activity	Description	Frequency
Remote Controlled Switch - Annual Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with Network Control Room to ensure correct operation and indication.	Annually
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance.	5 yearly

Figure 6-41 Inspection and Routine Maintenance Schedule for Overhead switch equipment

All overhead switches and links are treated in the same manner, and are maintained under the preventative maintenance programme detailed above. Overhead HV fuses are visually inspected during both the annual overhead line survey and at the time of transformer maintenance (for fuses supplying overhead transformers), The large quantity and low risks associated with fuses does not justify an independent inspection and maintenance programme. Remote controlled overhead switches are operationally checked annually to ensure correct operation and indication, from both local and remote (SCADA) control points. This is achieved by closing a bypass link, or backfeeding from either side.

6.4.10.2. Condition of overhead switches, links and fuses

Generally, the condition of overhead equipment on the Wellington network is good. The environment subjects equipment to wind, salt spray, pollution and debris which causes a small number of units to fail annually. Common modes of deterioration are corrosion of steel frame components and operating handles, mechanical damage to insulators, as well as corrosion and electrical welding of contacts. In harsh environments, fully enclosed gas insulated switches with stainless steel components are now being used.

A problem has previously been identified with some types of expulsion drop out (EDO) fuses that are overheating, which as a result of the use of different metals is causing the pivot point on the fuse holder to seize and this is preventing the fuse holder from operating as designed. The situation is being monitored and, if warranted, a replacement programme will be put in place. Over the past two years this has not been an issue and therefore replacement only occurs as required.

The coastal environment around Wellington causes accelerated corrosion on galvanised overhead equipment components and where possible, stainless steel fittings are preferred as they have proven to provide a longer component service life. These high quality components come at a cost premium.

6.4.10.3. Renewal and Refurbishment

There is no structured programme to replace overhead switchgear or devices. Any renewal activity on these assets is driven from standard inspection rounds and resultant maintenance activities arise from the identification of corrective work. With the extensive pole and crossarm replacements undertaken over recent years, a large number of overhead switches have been replaced. Replacement generally occurs following a poor condition assessment result from the routine inspections, or at the time of pole or crossarm replacement if the condition of the switch justifies this at that time.

An allowance in the CAPEX programme for HV switchgear replacement funds the required replacements that do not occur in conjunction with other projects.

6.4.11. Auto Reclosers and Sectionalisers

6.4.11.1. Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on auto reclosers and sectionalisers.

Activity	Description	Frequency
Visual Inspection and Thermal Image	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections.	Annually
Recloser and Sectionaliser - Annual Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with Network Control Room to ensure correct operation and indication.	Annually
Recloser & Sectionaliser Service	Maintenance of recloser, inspect and maintain contacts, change oil as required, prove correct operation	3 yearly
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance	5 yearly

Figure 6-43 Inspection and Routine Maintenance Schedule for Auto Reclosers and Sectionalisers

6.4.11.2. Condition of auto reclosers and sectionalisers

The majority of the units in service are in good condition. From inspection activities the bases of a number of units have surface corrosion that can be addressed under the corrective maintenance programme. Testing of some recloser units in-situ is limited, and it has been found that several McGraw-Edison KFE reclosers have not been working as intended.

The operational performance of auto reclosers is evaluated from fault information, which indicates whether the unit performed as expected.

6.4.11.3. Renewal and Refurbishment

A programme of replacement of older, poor performing reclosers will commence in the 2013/14 period. In recent years there have been reliability and automation projects undertaken, and as a result there are appropriately placed reclosers and sectionalisers in service.

One McGraw-Edison KFE recloser (Moeraki Road) was replaced in 2012 and another three units were found to be not operating correctly after inspection. These are located in Whiteman's Valley (Katherine Mansfield), Wainuiomata Coast (Jacksons Farm) and Judgeford (Moonshine). The units were repaired and maintained, and tested to prove correct operation. However the future service life is largely unknown as they may fail again in the short term following repair. The replacement reclosers will be SCADA controlled using radio where available, which is consistent with modern industry practice.

Reyrolle OYT reclosers are now beyond their service life, and some have been known to mal-operate, leading to the zone substation feeder tripping. Upon re-energisation of the feeder the recloser continues its cycle and trips again. These units are simply replaced when this fault is found to be due to their age.

A replacement program will be undertaken for the next five years to replace reclosers that have been in service for more than 40 years, or those found to have poor reliability. These will initially start with one recloser in the 2013/14 period, and will be incorporated in the Switchgear Replacement Programme budget.

Replacement year	No of Reclosers	Proposed Budget
2013	1 unit	$65,000
2014	2 units	$130,000
2015	2 units	$130,000
2016	2 units	$130,000
2017	2 units	$130,000

Figure 6-45 Proposed Auto-Recloser Replacement Spend Plan

6.4.12. HV Distribution Substations and Equipment

6.4.12.1. Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on distribution substations and associated equipment:

Activity	Description	Frequency
Inspection of Distribution Substations	Routine inspection of distribution substations to ensure asset integrity, security and safety. Record and report defects, undertake minor repairs as required. Record MDIs where fitted.	Annually
Grounds maintenance - Lump sum	General programme of grounds and building maintenance for distribution substations	On going
Fire Alarm Test	Inspect and test passive fire alarm system	3 monthly
Visual Inspection and Thermal Image (Ground Mount Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annual
Visual Inspection and Thermal Image (Pole Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections.	Annual
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance	5 yearly

Figure 6-46 Inspection and Routine Maintenance Schedule for HV Distribution Substations and Transformers

Activity	Description	Frequency
Visual Inspection of Switchunit	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
Switchunit Maintenance (Magnefix)	Clean and maintain Magnefix unit, inspect and replace link caps as required, test fuses, check terminations where possible.	5 yearly
Switchunit Maintenance (Oil Switch)	Clean and maintain oil switch unit, drain oil and check internally, check terminations and cable compartments. Ensure correct operation of unit. Refill with clean oil.	5 yearly
Switchunit Maintenance (Vacuum or Gas Switch)	Clean and maintain switch unit, check terminations and cable compartments. Ensure correct operation of unit. Check gas / vacuum levels.	5 yearly

Figure 6-47 Inspection and Routine Maintenance Schedule for HV Switch Units

6.4.12.2. Distribution Switchgear Condition

The switchgear installed on the Wellington Electricity network is generally in good condition and comprises both oil and gas insulated ring main units, as well as solid resin insulated equipment. Routine maintenance addresses the majority of minor defects, and on occasion a unit requires replacement when the condition is unacceptable. Common condition issues experienced include mechanical wear, both of the enclosure/body as well as operating mechanisms, electrical discharge issues or poor oil condition and insulation levels.

Some specific condition issues are noted below:

<u>Solid Insulation Units - Magnefix/Krone</u>

Magnefix switchgear is cleaned five-yearly, with targeted cleaning for a number of sites undertaken more frequently as a corrective maintenance activity. Magnefix switchgear is generally reliable however there are specific cleaning requirements to avoid tracking problems associated with the resin body casing due to the accumulation of dust and other deposits (such as blown salt and diesel fumes).

There have been past experiences of Magnefix failures on the network due to a suspected termination failure mode. It is believed that the early style “figure 8” connectors on some older units (typically installed between 1968 and 1975) fail under heavy loads due to heating and thermo-mechanical problems. The failures have all been experienced on residential feeders with recent load growth, during the winter evening peak. A survey of older units has shown a number with low or leaking termination grease levels which may be a physical sign of heating in the connector. These units are prioritised for termination replacement using new connectors and heatshrink terminations if evaluation indicates the unit does not need replacement due to age, other conditions or operational factors. Wellington Electricity has targeted around 40 units a year for replacement of connections, and these are prioritised from information obtained during routine inspections. Aside from the connector issue, these units are not at end of life and replacement of the connections is considered to be an effective and efficient maintenance activity.

Andelect SD Series 1 and 2

There is presently an operational restriction on Series 1 SD switchgear. There were 12 identified sites having equipment of this type and these have all been replaced during late 2012 and early 2013 to address the known mode of failure and inherent safety concerns.

A number of ABB Series 2 SD switchgear units were found to have a problem with oil contamination and the majority of units have been prioritised for maintenance (complete shutdown and oil change) to address this issue. This type of switchgear once maintained is generally in good condition and reliable and does not present a significant risk to the network. This risk is controlled by preventing live switching on the units until a maintenance history was known, or the unit was fully maintained.

Substation Switching Access

In 2012 following a serious incident, an issue was identified that some sites have limited access to conduct safe switching as a result of vegetation, encroaching fences or landscaping, or poor site design. Some of the sites have had the obstructions removed, or where this is impractical, a different type of ring main unit is used which require a smaller area of switching space. This issue is being monitored through the routine inspection programme.

Statter, and Long and Crawford

There are a number of Statter, and Long and Crawford type ring main switches installed on the Hutt Valley network. These have been installed in outdoor cage substations and are subject to harsh environments. Where possible these are being replaced in conjunction with other distribution upgrades due to age and condition. Some networks have experienced catastrophic failures of early Statter switches in outdoor environments. As part of the routine inspection programme, Long and Crawford units in poor condition are identified and schedule for corrective repairs or replacement. A replacement programme will be started in 2013 to replace the end of life Statter switchgear typically with standard ring main units.

6.4.12.3. Renewal and Refurbishment

HV Distribution Switch Gear (Ground Mounted)

Note – This section excludes circuit breakers which are discussed in a previous section.

Any minor defects or maintenance issues are addressed on-site during inspections. This may include such maintenance as topping up oil reservoirs, replacing bolts, rust treatment and paint repairs. Major issues that cannot be addressed on site usually result in replacement of the device. Likewise, replacement of the device is carried out if it is unsafe or if it is uneconomic or impractical to undertake a repair on site. Wellington Electricity has an ongoing refurbishment and replacement programme for all ground mounted distribution switchgear. Provision is included in the asset replacement forecast to fund this programme. The drivers for replacement of ground mounted switchgear include:

- The assessed condition of the equipment
- The availability of spare parts
- The switchgear insulating medium
- The location on the network and consequence of failure.

The continued use of oil insulated switchgear has been reviewed and the decision made to make use of other types such as vacuum or gas (SF_6) insulated types in future. When any switchgear device fails, the reason for the failure is studied and followed up with a cost benefit analysis to determine the best option from repairing, refurbishing, replacing or decommissioning the device and others of the same type. There are several types of ring main switch that have identified issues around age, condition and known operational or historic issues. These include early Reyrolle oil switches (LDI, JKSS, IA18), AEI, Statter, Long and Crawford, and early Andelect switches. These will be replaced based on the risks associated with each type, and summarised later in the document (these programmes are in addition to the annual budget for switch replacement).

Low Voltage Distribution Switch Gear (Substation)

Low voltage distribution switchgear and fusing is maintained as part of routine substation maintenance and any issues arising are dealt to at that time. The Wellington city area has a large number of open LV distribution boards in substations, and a safety programme has been undertaken to cover these with clear Perspex covers. As additional sites are identified they are completed, with a small annual allowance made to capture any sites missed in the original programme. Smaller substations have a higher level of shielding on many of the installations.

The overall performance of LV distribution switchgear and fusing is good and there are no programmes underway to replace this equipment. All new installations use DIN-style fuse disconnectors which are safe, reliable and low maintenance.

Distribution Transformers

If a distribution transformer is found to be in an unsatisfactory condition during its regular inspection it is programmed for corrective maintenance or replacement. An in-service transformer failure is rare and if it should occur it is investigated to determine the cause. Based on this assessment a decision is made to repair, refurbish, or scrap the unit depending upon the most efficient outcome given costs and residual life of the unit. Typical condition issues include rust, heavy oil leaks, integrity and security of the unit. Some minor issues such as paint, spot rust and small leaks can be repaired and the unit will be returned to service on the network. The refurbishment and replacement of transformers is an ongoing programme, which is provided for in the asset maintenance and replacement budget, however it is undertaken on a needs basis (condition, loading, etc) arising from inspection rather than by age.

In addition to the transformer unit itself, the substation structures and associated fittings are inspected and replaced as need be. Examples include distribution earthing, substation canopies and kiosk building components (such as weathertightness improvements). Some renewal may be costly and time consuming as a large number of berm substations in the Hutt Valley area are an integral substation manufactured during the 1970s and 80s by the likes of Tolley Industries. Replacement of these units will require complete foundation replacement and extensive cable works. Given the high number of these in service, a compatible replacement unit is being developed with a transformer manufacturer to allow like for like replacement at much lower cost than complete replacement of the entire substation.

Wellington Electricity prefers to use a canopy type substation with independent components (LV switchgear, HV switchgear and transformer under a removable metal canopy) for new installations where practicable, however cost and space constraints often mean integral substations are used. The benefit of a canopy type substation is that it allows for component replacement or upgrade, or canopy replacement without affecting the entire installation. This will reduce the overall life cycle cost.

Wellington Electricity has reviewed the construction standards for overhead transformers. Previously, transformers up to 300kVA were mounted on overhead structures. A number of electricity lines businesses have made a move away from mounting transformers above 150kVA due to seismic and safety concerns. Modern transformers of 150kVA and 200kVA are now lighter than old 150kVA units and the largest pole mounted transformer for replacement installations is 200kVA.

Distribution Cables

Maintenance of the underground distribution cable network is limited to visual inspections and thermal imaging of cable terminations. Cables are operated to failure and then either repaired or sections replaced. A more intensive maintenance regime is not considered cost effective, given that the network is generally designed so that supply can be maintained while cable repairs are undertaken.

A known issue on the 11kV network is a type of joint kit installed on early XLPE cables between 1980 and 1983 that did not adequately seal between XLPE and PILC cables on the outer sheath. These have been mostly remedied, however some may still exist. No active programme is in place to test or repair these joints however it is noted and in time if performance deteriorates then a programme may be initiated.

Cable replacements are prioritised based on a combination of fault history and frequency together with tests undertaken after earlier cable fault repairs. Cable replacements will be targeted at cables exhibiting high fault rates, or showing poor test results following a repair. Recent issues with cables on the network highlight the effect of fault stresses on older joints and the need to overlay sections of cables due to repeat joint failures. The small number of natural polyurethane insulated cables is most likely to show high failure rates and hence this type of cable is more likely to be replaced following a cable fault. An allowance is made each year in the CAPEX programme to replace cable based upon historic trends and known defects. Capacity upgrades are also considered and more details are provided in Section 5 (Network Development).

In 2012 there were 31 occasions of cable fault and cable joint failures. Underground cables usually have long life and high reliability as they are not subjected to environmental hazards being underground, however as these systems age and reach the end of life, performance is seen to decrease. External influences such as third party strikes, inadvertent overloading, or even unusual high loading within normal conditions can reduced the service life of cables. Some instances of failure are due to workmanship on newer joints (which can be addressed through training and education), whilst others are due to age or environment which is less controllable. This has resulted in a high SAIDI impact and is discussed further in Section 7 (Network Performance).

Cable Terminations

Cable termination replacement is driven by visual inspection, either showing signs of discharge, or significant compound leaks, as well as analysis of fault rates. The exception to this is 11kV cast metal pothead terminations where analysis of fault rates, together with a risk assessment, has resulted in a decision to replace them with heat shrink terminations.

During recent years, there has been a continued increase in the number of older outdoor heatshrink terminations that have failed in-service. This has become a concern and upon examination of the failed asset it appears that workmanship is again often the cause, with sealing mastic at the lug end of each phase not appropriately applied, or the heatshrink not adequately shrunk down or cut back too far. Over time moisture ingress occurs and eventually the termination blows out at the crutch. The terminations were all in excess of 15 years old, and the heatshrink material had not failed. Reminders and training refreshers are given to staff following such findings.

6.4.13. Low Voltage Pits and Pillars

6.4.13.1. Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on low voltage pits and pillars, either for consumer service connection and fusing, or network low voltage linking:

Activity	Description	Frequency
Inspection of Service Pillars	Visual inspection and condition assessment of service pillar, minor repairs to lid as required.	5 yearly
Inspection of Service Pits	Visual inspection and condition assessment of service pit, minor repairs as required.	5 yearly
Inspection of Link Pillars	Visual inspection and condition assessment of link pillar, thermal imaging and minor repairs as required.	5 yearly
U/G link box inspection including Thermal Image	Visual inspection and condition assessment of link box, thermal imaging and minor repairs as required.	5 yearly

Figure 6-51 Inspection and Routine Maintenance Schedule for LV Pits and Pillars

Starting in 2011, Wellington Electricity has included a loop impedance test to check the condition of the connections from the fuses to the source in underground pillars. Where practical, damaged pillars are repaired but otherwise a new pillar or a pit is installed.

6.4.13.2. Renewal and Refurbishment

Pillars are generally replaced following faults or reports of damage. Pillars with a high likelihood of future repeat damage by vehicles are replaced with pits. When large groups of older pillars, such as concrete or 'mushroom' type, are located and their overall condition is poor they are replaced as repair is impractical or uneconomic.

There are a number of different variants of service connection pillars on the network that are being replaced in small batches, notably under-veranda service connection boxes in older commercial areas.

There is ongoing replacement of underground link boxes around Wellington city. Many link boxes have deteriorated to a point where they may not be safe to operate under some conditions or they may not provide reliable service. Condition is identified through routine inspections and sites prioritised for replacement as an outcome of this work. The link boxes are either being jointed through, where the functionality is no longer required, or they are replaced entirely to provide the same functionality. These replacements are driven from the poor condition of some of these link boxes which are now over 50 years old. A complete survey was undertaken in 2009 that provided condition assessment data to allow for renewal programmes in subsequent years. The majority of unserviceable link boxes have been replaced, so it is expected that fewer than 10 will require replacement every year. For the remainder of the planning period the link boxes will be replaced following an unsatisfactory inspection outcome.

An allowance is made each year in the CAPEX programme to replace service pillars that have become badly damaged, or replacement with pits in areas subject to vehicle damage. This budget is based upon historic trends but rarely exceeds 60 units per year.

6.4.14. SCADA

The SCADA system is generally self monitoring and as such there is little preventative maintenance carried out on it apart from planned server and software upgrades and replacement. Master station maintenance is broken up into two categories: (a) hardware (b) software.

(a) Hardware support for both Haywards and Central Park (disaster recovery site) is provided as required by Wellington based maintenance contractors.

(b) Software maintenance and support is provided by external service providers.

Existing RTUs do not have full back up capability and are managed on a run to failure strategy. First line maintenance on the system is carried out as required by the maintenance contractor within the scope of its substation maintenance contracts. The substation level IP network is monitored and supported from within New Zealand by the respective service providers of the IP network infrastructure.

The SCADA master station at Haywards has a UPS system to provide backup supply and there is a UPS installed at Petone to provide supply to the operator terminals in the Network Control Room. This is subject to a maintenance programme provided by the supplier of the equipment. In addition, this unit has dual redundancy of converters and batteries so provides a high level of supply security in the unlikely event of failure.

6.4.14.1. Condition Assessment of SCADA System Components

C225 RTU

There are 20 of this type of RTU in service on the network. Power supply failure is the most common failure mode with around one failure a year. Spares are held at a central location and repairs are carried out when possible. These are being replaced in conjunction with substation switchgear replacements and the redundant units held as spares.

C5 RTU

These RTUs are placed in very small distribution substations and there are six in service. These RTUs are no longer manufactured and are difficult to repair so as they fail they are interchanged with current technology alternatives.

Load Control PLC

There are 23 of this type of PLC in service on the network. Installed in 1996, these Toshiba PLC's are used to drive load control equipment. This type of PLC is an obsolete item however one spare is held for cases of failure. These will be addressed as part of any Load Control upgrade and are unlikely to be replaced outside of any other replacement programme.

Dataterm RTU

There are 6 of these in service on the network. These RTU's have an inherent design flaw in the analogue card which, over time, causes the analogues to "jump". This is repairable with the replacement of reed relays on the analogue card with an approximate cost of $500 per card. There are normally four cards per RTU and the cards fail at a rate of about five per year. These units are being replaced with Foxboro SCD5200 RTUs as zone substations are upgraded and moved onto the IP network.

Miniterm RTU

There are 59 of these in service on the network. These units fail at the rate of approximately two a year due to board level IC failure, with replacement ICs gradually becoming harder to source. These RTU's cannot be directly replaced by current technology, however spare units are becoming available as a result of the switchgear replacement works. There is no active programme for replacing these however they are being replaced in conjunction with substation switchgear replacements, or where a risk or shortfall is identified with having this type of RTU installed.

Common Alarms

There are 49 of these in service on the network. These are a custom built device, placed in minor "ringed" distribution substations to give an indication back to control room of a tripping event. They are prone to failure and there are no spares. On failure, the units are being replaced by current technology such as a low cost RC02 RTU which is widely used on the network.

6.4.14.2. Asset Renewal and Refurbishment

The asset replacement budget also provides for the ongoing replacement of obsolete RTUs throughout the network. Obsolete RTUs that may present a significant impact on network reliability are being targeted first with special attention being paid to the zone and major switching substations.

Where there is an RTU which exists at a zone substation or major switching points in the network that is adjacent to the existing TCP/IP network, consideration is given to upgrade equipment to allow TCP/IP connection in order to continuously improve communication system reliability.

Further, the TCP/IP infrastructure will also allow other substation based equipment, such as security alarms etc., to efficiently communicate with distant receive devices.

Master Station

As detailed earlier in this document, the SCADA master station has been replaced with a GE ENMAC system. This new unit will last at least five years. Some expenditure is foreseen during this planning period on the master station related to hardware and software upgrades, as well as commissioning tests on field devices and communications links. Elements of the existing Leeds and Northrup 2068 master station will be retained in the short term to run the automatic load control packages. This will in time be integrated with the ENMAC system.

Siemens Power Automation System (PAS)

The PAS unit acts as a protocol converter between IEC61850 field devices and that of the DNP3 SCADA master station. In the short term, a project may be undertaken to separate the three sites from the PAS.

Substation base equipment could be installed which consists of SCD5200 RTUs than can convert the substation 61850 protocol directly to DNP3. This is still being investigated and no budget provision has been made at this time.

Remote Terminal Units (RTUs)

All Foxboro C25 and C225 remote terminal units (RTUs) at GXPs were replaced during 2011 for two reasons:

1. The new GE ENMAC SCADA master station has no automatic load management facility and in order to implement this, the present Foxboro L&N2068 master station will be required to be maintained in the short term to provide the load management system. This was achieved with the use of SCD5200 RTUs at the GXPs providing information to both master stations.

2. The upgrade coincides with Transpower's move to TCP/IP networks and the resulting loss of the serial link presently used by Wellington Electricity from GXPs back to Haywards.

The substation RTU replacement programme will start with the 3 sites in the Wellington city area that have Plessey Dataterm RTUs installed. One of these sites, Karori, has a Reyrolle Type C gear switchboard that is targeted for replacement in 2014. At this site the RTU upgrade will occur as part of the switchboard upgrade project. The remaining sites (Hataitai and Ira Street) are targeted for replacement alongside these upgrades, however as spares are made available from the first sites, the remaining sites may be able to be kept in service longer if input and output (I/O) capacity and functionality constraints are not present.

There is currently no programme to replace RTUs at distribution substations, as these sites generally have a lower risk profile than GXPs and Zone Substations and replacement can occur upon failure of the RTU. However where a specific risk is identified the RTU upgrade will be scheduled. Additionally, sites that have switchgear upgrades may have an RTU upgrade however these are incorporated as part of the specific project and evaluated on a case by case basis.

From 2013 onwards, Wellington Electricity will commence the replacement of the remaining C225 RTUs installed at 17 zone substations with an aim to complete all replacements by 2018 (by which time the units will be at end of their service life).

The medium term replacement plan for substation RTU replacement is shown below.

Site	Site type	Present RTU	Proposed RTU	Driver	Replacement year
Petone	Zone Substation	C225	SCD5200	Protection Upgrade	2013
Maidstone	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2013
Brown Owl	Zone Substation	C225	SCD5200	GXP Protection Upgrade	2013
Karori	Zone Substation	Dataterm	SCD5200	Switchgear Replacement	2014
Hataitai	Zone Substation	Dataterm	SCD5200	Age	2014

Site	Site type	Present RTU	Proposed RTU	Driver	Replacement year
8 Ira Street	Zone Substation	Dataterm	SCD5200	Age	2014
Waitangirua	Zone Substation	C225	SCD5200	Age	2014
Trentham	Zone Substation	C225	SCD5200	Age	2014
Gracefield	Zone Substation	C225	SCD5200	Switchgear Replacement	2015
Tawa	Zone Substation	C225	SCD5200	Age	2015
Porirua	Zone Substation	C225	SCD5200	Age	2015
Titahi Bay	Zone Substation	C225	SCD5200	Age	2015
Kenepuru	Zone Substation	C225	SCD5200	Age	2016
Korokoro	Zone Substation	C225	SCD5200	Age	2016
Waterloo	Zone Substation	C225	SCD5200	Age	2016
Naenae	Zone Substation	C225	SCD5200	Age	2017
Seaview	Zone Substation	C225	SCD5200	Age	2017
Wainuiomata	Zone Substation	C225	SCD5200	Age	2017

Figure 6-53 Proposed RTU Replacement Programme

Analogue Radio Replacement

It has been identified through the work on the Network Communications Strategy that there is a risk associated with the age and configuration of the analogue radio network that is used for a number of field devices (such as reclosers and remote switches). An upgrade of the repeaters located at Mt Climie and Mt Kaukau, as well as a secondary repeater at Stokes Valley, may be undertaken within the medium term. With this system upgrade, communications components at the field devices, such as radio modems, may also require upgrading. The private radio network provides a number of strategic benefits including lower costs of operation than using cellular networks, and a high level of resilience following a major event when cellular networks may be overloaded or unavailable. This replacement programme needs to be developed further and is not presently budgeted in a specific year. The estimated order of cost for this work is $250,000 to $300,000.

6.5. Asset Renewal and Refurbishment Programme

6.5.1. Asset Replacement Projects for Current Year

The major asset replacement projects (greater than $100,000) that Wellington Electricity is planning to complete in the 2013 period, as detailed in Section 6 (Lifecycle Asset Management), are summarised below:

Pole Replacement Programme – 2013	
Driver: Asset Integrity and Safety Estimated cost: $3.0 million	A new wood pole testing programme (the Deuar method) is already in place. Replacement of red and yellow tagged poles will continue in 2013, managed as packages of work following inspection. This work includes replacement of associated pole hardware. This budget is derived from historic levels of pole replacement (around 7.5% of population inspected) and realistic replacement levels given current resourcing.

Karori 11kV Switchboard Replacement – 2013	
Driver: Asset Integrity and Safety Estimated cost: $1.74 million	Following the "Stage of Life" analysis of zone substation switchboards, the Karori substation switchboard was found to have the highest consequence of failure due to high loading, given its age and condition. Full replacement of this switchboard and associated protection, control and secondary systems is planned to commence in 2013 and be commissioned in 2014.

Reyrolle Type C Replacement – 2013	
Driver: Asset Integrity Estimated cost: $1.95 million	This project involves the replacement of Reyrolle C-type 11kV switchgear at the following distribution substations: Kilbirnie , 9 Parkvale Rd and 139 Thorndon Quay

Cornwell St substation decommissioning and network reconfiguration - 2013	
Driver: Asset Integrity Estimated cost: $275,000	Decommissioning the Cornwell St substation and reconfiguring the 11kV network as an alternative to the replacement of the aging Reyrolle Type C switchgear which is underutilised and supplies only a small load at the Port of Wellington.

Yorkshire SO-HI Replacement – 2013	
Driver: Asset Integrity Estimated cost: $1.0 million	This project is the first stage of a proposed four year programme to replace Yorkshire SO-HI 11kV switchgear from distribution substations on the network. It is expected that 12 of the highest priority sites will be addressed in 2013.

Maidstone 10/Vitafoam Protection Upgrade – 2013	
Driver: Asset Integrity and Safety Estimated cost: $100,000	A section of the Whiteman's Valley area is protected by a circuit breaker at the Vitafoam substation which does not co-ordinate correctly with the downstream circuit breaker, and upstream feeder breaker and also can prove difficult to access the substation to reset the circuit breaker. It is proposed to replace the protection scheme in this area to ensure correct operation.

Zone RTU Upgrade (Maidstone, Brown Owl, Petone) - 2013	
Driver: Asset Integrity Estimated cost: $350,000	This project is to replace the zone substation RTU with an SCD5200 RTU and upgrade to TCP/IP communications as the existing RTU is at the end of its service life and (in the case of Brown Owl and Maidstone) is related to the Transpower GXP upgrade work and Wellington Electricity protection upgrades.

Evans Bay RTU Replacement – 2013	
Driver: Asset Integrity Estimated cost: $100,000	This project is to replace the substation RTU at Evans Bay with a SCD5200 RTU and upgrade to TCP/IP communications as the existing RTU is at the end of its service life and has insufficient I/O. The project is inline with the Evans Bay switchboard replacement that commenced in 2012.

Transpower GXP redevelopment works (UHT/WIL/TKR) - 2013	
Driver: Asset Integrity Estimated cost: $500,000	Transpower is proposing to replace the outdoor 33kV bus at Wilton in 2014 and Upper Hutt and Takapu Rd in 2015. This project makes an allowance for design and associated work with installing new protection and GXP equipment at these sites.

Zone Substation Switchgear PD Mitigation and Upgrade - 2013	
Driver: Asset Integrity Estimated cost: $250,000	This project is to replace components that are identified to be the source of high PD on several Reyrolle LMT switchboards.

Titahi Bay 11kV Backup Protection at Porirua – 2013	
Driver: Asset Integrity and Safety Estimated cost: $100,000	As Titahi Bay is being supplied from Porirua Zone substation, there is a need to provide back up protection between the two zone substations by installing relays at Porirua Zone substation on the Titahi Bay feeders.

Ngauranga 9 Line Refurbishment – 2013	
Driver: Asset Integrity Estimated cost: Stage 1 - $320,000	Ngauranga 9 has recently been one of the worst performing feeders due to a section of overhead network which as reached end of life. This project is to replace a section of this feeder and rebuild the overhead network around the Newlands and Johnsonville area.

Wainuiomata Coast Road Upgrade – Stage 2 – 2013	
Driver: Asset Integrity Estimated cost: $200,000 – Stage 2	Following poor performance on the Wainuiomata Coast Road areas, line rebuild of Wainuiomata 7 feeder will occur in a 10-stage project, with Stage 1 completed in 2012 and Stage 2 to commence in 2013. This involves 78 poles out of the 385 poles in the Coast Rd area.

Karori 2 Overhead Line Rebuild – Stage 2 - 2013	
Driver: Asset Integrity Estimated cost: $150,000 – Stage 2	The Karori 2 feeder towards Makara has historically performed poorly, especially during adverse weather. The terrain is harsh and exposed in places, as well as being covered in dense vegetation making access difficult. This is the second stage of nine. This involves the 29 poles and reconductoring of 29 spans to address reliability concerns arising from hardware condition.

In addition to the specific projects above, Wellington Electricity also makes provision for programmes of replacements that arise from condition assessment programmes during the year, a list of programmes with a forecast cost greater than $100,000 are listed below:

Driver	Programme	Forecast cost
Asset Integrity	Transformer and Canopy Replacement	$1,250,000
Asset Integrity	Cable and Conductor Replacement	$500,000
Asset Integrity	Distribution Switchgear Replacement	$1,250,000
Asset Integrity	Protection and Secondary Systems	$350,000
Asset Integrity	Crossarm Replacement	$100,000
Safety	Lock Replacement	$50,000
Safety	Earthing Upgrades and Compliance	$300,000
Safety	LV Pillar and Pit Replacement	$100,000
Safety	Asbestos Removal	$50,000
Safety	Fault Passage Indicator Replacement	$25,000
Safety	Common Alarm Replacement	$90,000
Safety	WCCL Changeovers	$500,000

Figure 6-54 Asset Replacement Programme

6.5.2. Prospective Asset Replacement Projects for 2014 – 2018

The projects included in this section are less certain in nature. Whether or not they proceed, and their timing, will largely depend on the risks to the network that need to be mitigated, and the relative risk compared with other asset replacement projects. The timing of asset renewal projects is directly related to the risks associated with the works, and changes to these alter the timing of the projects. It is assumed that the rate of deterioration, aging, and the increases of load remain constant. Should the loading or type of load served significantly change, and hence increase in the consequence of failure, or if the asset deteriorates faster than expected, then renewal may need to be brought forward. Conversely, should the risk level decrease, then the project may be able to be deferred until later in the planning period, or an alternative found. These projects are aimed at ensuring existing service levels are maintained in a sustainable manner, and in line with the surveyed feedback from consumers.

33kV Cable Replacement	
Driver: Asset Integrity Estimated cost: $21 million	A number of subtransmission circuits with utilisation constraints will be addressed under Network Augmentation projects. However several in the top 10 have age and condition constraints. Palm Grove, University and Frederick Street will require complete or partial replacement during this medium term period, and a medium section of at least one other set will require replacement due to condition. This is detailed further in Section 5 and included in the network reinforcement budgets, but noted here as it resolves condition and age issues.

Zone Substation Transformer Replacement	
Driver: Asset Integrity Estimated cost: $4.0 million	Up to four zone substation transformers (33/11kV) are expected to need replacement based upon age and condition, with Evans Bay and Wainuiomata the most likely.

Pole Replacement Programme	
Driver: Asset Integrity and Safety Estimated cost: $3.0 million per annum	Replacement of red and yellow tagged poles will continue. This work includes replacement of associated pole hardware. Use of the Deuar pole test method and the decrease in the numbers of wooden poles is expected to produce a decline in the rate of replacement in the medium term.

Gracefield 11kV Switchboard Replacement	
Driver: Asset Integrity and Safety Estimated cost: $1.85 million (2014)	The Gracefield substation switchboard will be one of the oldest on the network after replacement of Palm Grove, Evans Bay and Karori. This will be the last Type C switchboard to replace. Full replacement of this switchboard and associated protection, control and secondary systems is planned to commence in the medium term.

Various 11kV Switchboard Refurbishments	
Driver: Asset Integrity and Safety Estimated cost: $3.0 million (2014-2016) ($0.5 million per site)	A number of zone substation switchboards were found to have a high consequence of failure due to high loading, but not particularly old age or poor condition. Full replacement of these switchboards is not justified, and retrofit components with higher ratings can be used to reduce the risks and provide a mid life refurbishment extending the overall life. Upgrades of associated protection, control and secondary systems is planned. The sites are Frederick Street, University, Moore Street, Hataitai, Kaiwharawhara and Johnsonville.

Reyrolle Type-C Replacement	
Driver: Asset Integrity Estimated cost: $472,000	This includes for the ongoing programmed replacement of Reyrolle C-type 11kV switchgear. This will target the remaining circuit breakers on the network in the medium term (to 2014).

Yorkshire SO-HI Replacement	
Driver: Asset Integrity Estimated cost: $1.0 million	The continued replacement of Yorkshire SO-HI switchgear will occur during this period (2014). This is expected to complete the SO-HI replacement programme.

Load Control Plant Replacement	
Driver: Asset Integrity Estimated cost: $3.0 million	Concerns have been raised around reliability and performance of early solid state ripple injection plant in the Wellington City area. During the medium term it is anticipated that plant at three locations will require upgrade to a modern low frequency. The plan for this is under development, however this investment has been allowed for in the budget forecasts.

In addition to the specific projects indicated above and programme allocations for undefined annual projects, the following table gives indicative asset category investment that is not yet defined, however is estimated due to asset age and known condition across the category.

Investment driver	Asset category	Investment
Asset Renewal	Distribution Switchgear Replacement	$7.5M
Asset Renewal	SCADA and RTU Replacement	$2.0M
Asset Renewal	Distribution Transformer Replacement	$7.5M
Asset Renewal	Distribution Cable and Conductor Replacement	$2.0M
Asset Renewal	Zone Substation Switchboard Replacement	$1.5M
Asset Renewal	Crossarm Replacement	$0.5M
Asset Renewal	Protection and Secondary Systems	$1.0M
Safety	LV Pillar and Pit Replacement	$0.5M
Safety	Cast Metal Pothead Replacement	$0.3M
Safety	Earthing Compliance Upgrades	$1.2M
Safety	Asbestos Removal	$0.3M
Reliability	Reliability Improvement Projects	$0.5M

Figure 6-55 Prospective Asset Replacement Programme 2014-2018

This investment profile is to maintain existing service levels, over time as condition information becomes better known, the category split may change.

6.5.3. Prospective Asset Replacement Projects for 2019 – 2023

Asset replacement and renewal projects that are listed in this section are less specific that the previous sections and are more uncertain in nature. There are few specific projects identified at this time, and the prospective investments are broken down as far as asset category only. As risks and needs change on the network, individual projects will change, however to maintain safety, security and reliability levels that the consumers are presently prepared to accept in their price/quality trade-off decision, the following investment levels will be required over this period. In addition, there will be programme works across each category to allow for unscheduled projects in each year.

Investment driver	Asset category	Investment
Asset Renewal	Pole Replacement	$5.0M
Asset Renewal	Subtransmission Cable Replacement	$25.0M
Asset Renewal	Load Control Plant Replacement	$6.0M
Asset Renewal	Power Transformer Replacement	$8.0M
Asset Renewal	Distribution Switchgear Replacement	$9.0M
Asset Renewal	SCADA and RTU Replacement	$0.5M
Asset Renewal	Distribution Transformer Replacement	$9.0M
Asset Renewal	Distribution Cable and Conductor Replacement	$7.0M
Asset Renewal	Zone Substation Switchboard Replacement	$3.0M
Safety	Earthing Compliance Upgrades	$2.0M
Reliability	Reliability Improvement Projects	$0.5M

Figure 6-56 Prospective Asset Replacement Programme 2019-2023

This investment profile is to maintain existing service levels, over time as condition information becomes better known then the category split may change to reflect the changing risks.

6.6. Asset Renewal and Replacement Expenditure

For clarity, the forecast provided below does not include the non-maintenance related operational expenditure of the business. Asset replacement and refurbishment costs are shown and it can be seen that the line item on which Wellington Electricity proposes to invest the most capital expenditure is asset replacement and renewals. This reflects the increasing age of the asset base.

Category	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Asset Replacement and Renewal	17,767	17,407	17,869	17,646	17,831	22,786	23,897	22,447	21,934	22,143	23,548
Reliability, Safety and Environment	978	820	780	602	636	697	691	679	685	691	694
Subtotal - Capital Expenditure on Asset Replacement and Safety	**18,745**	**18,227**	**18,649**	**18,248**	**18,467**	**23,483**	**24,588**	**23,126**	**22,619**	**22,834**	**24,242**
Service interruptions and emergencies maintenance	3,766	3,804	3,937	4,075	4,115	4,157	4,198	4,240	4,282	4,325	4,369
Vegetation management maintenance	1,126	1,146	1,195	1,236	1,258	1,280	1,303	1,325	1,349	1,372	1,396
Routine and corrective maintenance and inspection maintenance	6,655	6,766	7,048	7,294	7,415	7,539	7,664	7,792	7,922	8,053	8,188
Asset replacement and renewal maintenance	625	636	663	686	698	710	723	735	748	761	775
Subtotal - Operational Expenditure on Asset Management	**12,173**	**12,352**	**12,842**	**13,291**	**13,487**	**13,686**	**13,888**	**14,093**	**14,301**	**14,512**	**14,727**

Figure 6-57 Lifecycle Asset Management Expenditure Forecast – 2013 to 2023 ($000 in constant prices)

A breakdown of Preventative and Corrective Maintenance by Asset Category, over the 10 year period is shown in Figure 6-58. These numbers are based on long term averages and year on year variances across the asset categories occur depending on the nature of corrective maintenance that is required in any given year. The preventative maintenance component (routine inspections and maintenance) is agreed as part of the Field Services Agreement and remains relatively constant year on year.

Service Interruptions and Emergency Maintenance (Faults) can only be forecast and reported at a system level as the Field Service Agreement defines the rates for fault response services at a total level and not further broken into asset category detail levels.

Asset Replacement and Renewal Maintenance is similar to corrective maintenance and cannot be forecast at Asset Category level at present due to the varying nature of the work required. As Wellington Electricity develops more history around this expenditure category, forecasts and asset category splits can be enhanced. This is an area for future improvement.

Routine and corrective maintenance and inspection maintenance	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Battery / Secondary Systems	128	130	136	141	143	146	148	151	152	155	158
Cables (All Voltages)	613	623	650	672	683	695	706	717	730	742	754
Circuit Breaker	739	751	782	810	823	836	851	865	879	893	909
Distribution Substation	928	944	983	1,018	1,035	1,052	1,069	1,087	1,105	1,123	1,142
Distribution Transformer	1,609	1,635	1,705	1,763	1,793	1,822	1,852	1,883	1,916	1,950	1,979
Overhead Switch / Recloser	304	310	322	333	339	345	351	356	362	368	374
Pillar / Pit	158	160	167	172	175	179	182	185	188	191	194
Pole / Overhead Line	1,291	1,313	1,367	1,415	1,439	1,462	1,487	1,512	1,536	1,562	1,589
Power Transformer	180	183	190	197	200	204	207	211	214	217	221
Ring Main Unit / Ground Mount Switchgear	447	454	473	490	497	506	514	523	532	540	550
Zone Substation / GXP	258	263	273	283	288	292	297	302	308	312	318
Total	**6,655**	**6,766**	**7,048**	**7,294**	**7,415**	**7,539**	**7,664**	**7,792**	**7,922**	**8,053**	**8,188**

Figure 6-58 Preventative and Corrective Maintenance by Asset Category – 2013 to 2023 ($000 in constant prices)

6.7. Non-Network Asset Lifecycle Management - Renewal and Replacement

Wellington Electricity does not have a wide range of non-network assets, and therefore has limited need to renew and replace these assets.

6.7.1. Information Technology Assets

IT assets are replaced in accordance with the Information Technology Replacement policies, and IT equipment is replaced on a cycle between three and five years. Items such as telecommunications equipment may be replaced when service provider contracts are renewed.

A large investment item for this area is the development of a new Maintenance Management System, potentially SAP PM. Upgrades to business support software tools will made on a regular basis as new versions are required.

Investment will be required for additional computer hardware and software to provide for business continuity purposes. New equipment is procured as required for business needs.

Item	Regulatory Year	Estimated Cost
Computer Hardware Replacement	2013/14	$100,000

Item	Regulatory Year	Estimated Cost
GIS User Licenses	2013/14	$100,000
Maintenance System (SAP PM)	2013/14	$1,200,000
SCADA Data Historian	2014/15	$300,000
Network Planning and Analysis Tools	2014/15	$200,000
ENMAC Upgrade	2014/15	$1,200,000
Load Control Master Station Upgrade	2014/15	$300,000

Figure 6-59 Overview of planned IT Asset Investment

6.7.2. Plant and Machinery

Leased vehicles are replaced on a time basis in accordance with Wellington Electricity's Motor Vehicle Policy. It is expected that the fleet will be renewed over the short term (typically every three years) and on an ongoing basis thereafter.

There is provision in the 2013 non network CAPEX programme to extend the Deuar license and to purchase an additional test set. Other test equipment and tools are replaced as required, these include power quality and partial discharge test sets.

Item	Regulatory Year	Estimated Cost
Specialist Test Equipment and Licenses	2013/14	$300,000

Figure 6-60 Overview of planned Plant and Machinery Investment

There are no other material investments planned for non-network plant and machinery.

6.7.3. Land and Buildings

Wellington Electricity expects minimal investment or costs associated with the non-network land and buildings it owns. Costs include grounds maintenance and council rates on undeveloped sites.

6.7.4. Non-network Asset Expenditure Profile

Category	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Non-network assets	738	1,846	1,585	802	337	287	445	435	425	416	407

Figure 6-61 Non-Network Capital Expenditure Forecast – 2013 to 2023 ($000 in constant prices)

7. Network Performance

In addition to the management of assets at the component level, Wellington Electricity also monitors the performance of asset groups at the feeder level. The root cause analysis of faults and asset performance is part of the investigation to improve systems, standards and procurement. This provides a useful input to the asset maintenance process as it identifies feeders that are experiencing the most unplanned outages and hence may require remedial action to be undertaken in order to maintain network reliability.

Performance will also be compared with the security of supply standard to check that expected outage times are being met. In some cases, the terrain, exposure to elements or vegetation may conspire to result in multiple faults. Review of network configuration to reduce impact is considered as part of post-fault reviews.

7.1. Network Performance Analysis (2011/2012)

Wellington Electricity exceeded its reliability limits for SAIDI and SAIFI in 2011/2012 as shown in the table below:

Reliability metric	Limit 2011/2012	Actual for 2011/2012	Variance
SAIDI	40.74	45.879	+12.41%
SAIFI	0.6	0.735	+19.00%

Figure 7-1 Wellington Electricity Reliability 2011/12

The largest individual contributions to exceeding the limits were two extreme weather related events:

- A period of four days of snow in August 2011, which last happened in the Wellington region about 40 years ago
- A 'weather bomb' in early March 2012, where a severe storm front passed over Wellington bringing hurricane force winds and heavy rain.

Individually these events did not qualify as major event days; however, their impact was significant. Taken together, the above two incidents contributed a total of 11.505 minutes of SAIDI and 0.121 units of SAIFI. Although these one-off events are unable to be excluded from the final performance results, when deducted from the actual totals for 2011/12, the adjusted SAIDI and SAIFI for Wellington Electricity becomes 34.291 and 0.593 respectively. Figures 7.2 and 7.3 show that the general trend of network performance is within the target set by Wellington Electricity and the regulatory limit.

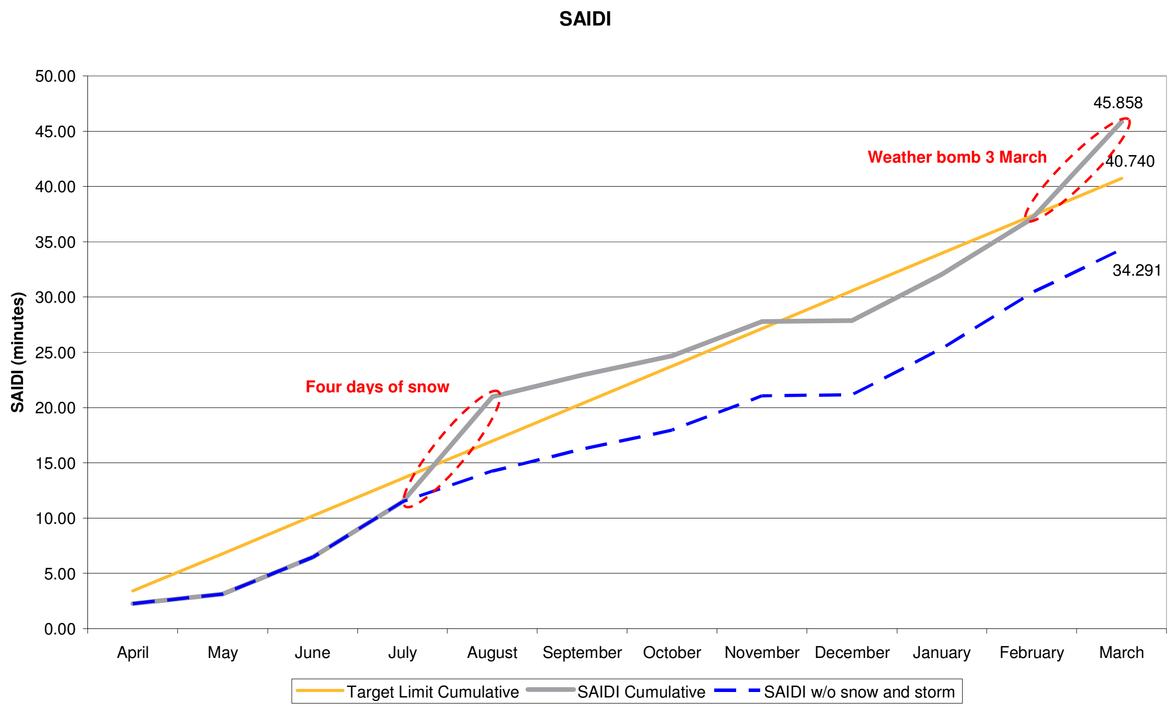

Figure 7-2 Wellington Electricity SAIDI Performance 2011/2012

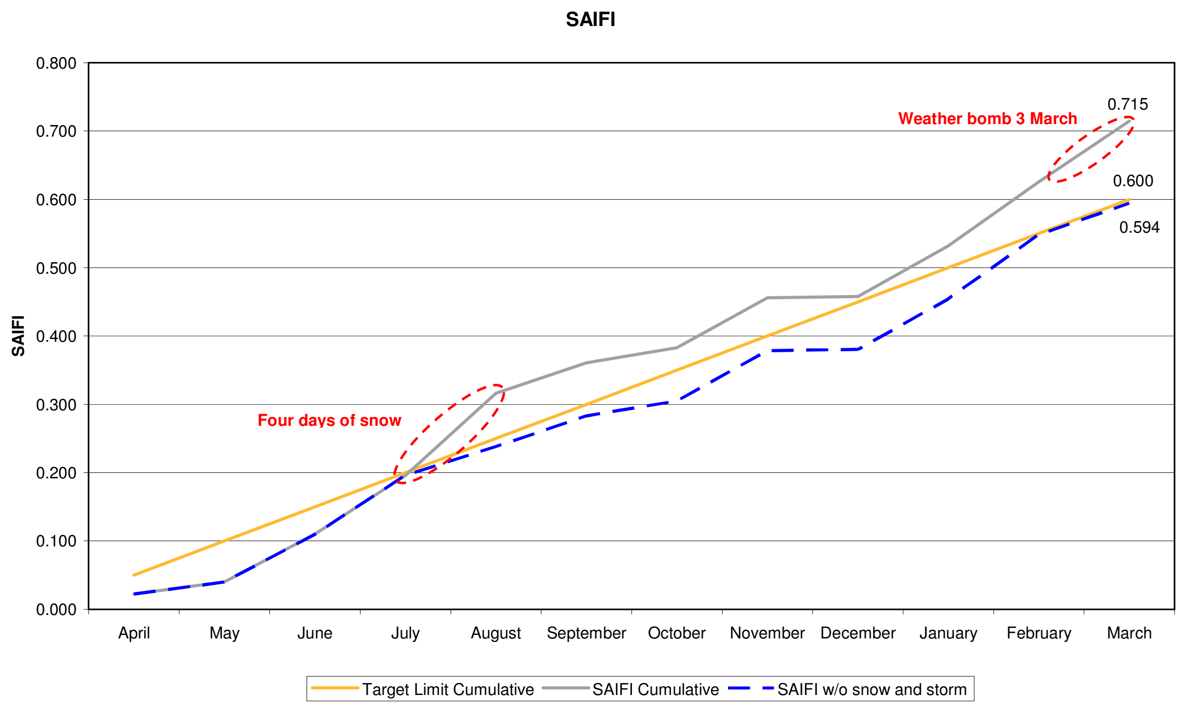

Figure 7-3 Wellington Electricity SAIFI Performance 2011/2012

7.1.1 Extreme Weather Events

The two extreme weather events (in 2011/2012) which caused multiple outages over a number of days with long restoration periods are described in detail below.

7.1.1.1 Event 1 - Four days of snow in August 2011

In August 2011, the performance of the Wellington Electricity network was heavily affected by four days of unusually severe cold weather. Ice and snow build up on lines, as well as snow laden branches on trees, combined with strong winds and lightning to cause a large number of outages throughout the region. Most of the affected customers were in rural areas which have dense vegetation. Prolonged outages resulted from roads being impassable, which made it difficult for responding crews to patrol and clear the lines. It was also difficult to work safely in the conditions.

During this event, Transpower had a complete outage at the Gracefield substation twice which caused a loss of supply to customers in the Seaview, Petone, and Wainuiomata areas. Transpower's grid supply into Wellington also suffered, with three out of four incoming circuits affected by the weather, leaving Wellington supplied by only one incoming transmission line. Auto-reclose events on the Transmission grid led to dips and power quality issues on the Wellington network.

Approximately 13,500 customers were affected by outages mostly due to trees and snow on lines. The total impact on reliability indicators for the snow event was:

- SAIDI: 6.719 minutes
- SAIFI: 0.081 units

7.1.1.2 Event 2 - Weather bomb in March 2012

On the 3 March 2012 a 'weather bomb' hit the Wellington region bringing gale force winds and heavy rain which lasted for 20 hours. This resulted in multiple outages due to trees and wind borne debris being blown into the overhead network, damaging assets and interrupting supply. Restoration of outages was prolonged due to safety concerns for response crews.

Over 6,000 customers were affected by outages mostly due to trees and debris falling onto lines. The total impact on reliability indicators for the weather bomb event was:

- SAIDI: 4.786 minutes
- SAIFI: 0.042 units

7.2. Reliability Performance by Fault Type

The 2011/12 SAIDI performance by fault type is shown in Figure 7.4, with comparison to the previous reporting period.

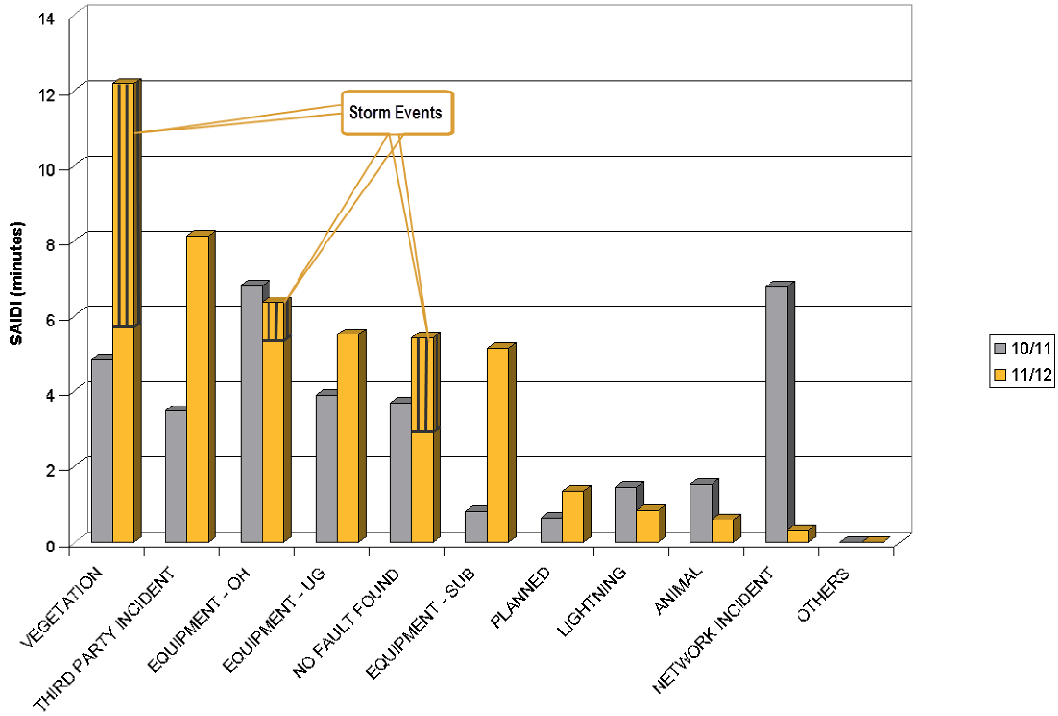

Figure 7-4 SAIDI Performance by Fault Type 2011/12

The highest impact on SAIDI for 2011/12 was due to vegetation fault type, followed by third party incidents. Both of these outage types require are influenced by external factors. When the storm events are excluded, the vegetation fault type shows consistent levels of impact compared with the previous year.

Wellington Electricity has a vegetation management programme however, under severe weather conditions vegetation outside of the controlled zones may interfere with the network and cause outages. Wellington Electricity is not considering raising maintenance expenditure to accommodate reducing vegetation interference during severe weather events as the costs are not justified against the benefits. Wellington Electricity will continue to work with tree owners to educate them on their obligations under the Electricity (Hazards from Trees) Regulations 2003 to maintain the standard clearances.

Improvements and control of third party damage relies upon the public or other utility installers not damaging network assets, usually as a result of excavating near network assets or vehicle collisions. Further safety campaigns for excavation companies have been carried out, and Wellington Electricity has maintained the free B4U DIG programme for the provision of plans and cable mark outs.

There were also increases in the areas of Underground Equipment, Substation Equipment and No Fault Found incidents. The root cause of equipment related faults has been determined and where practicable, maintenance programmes adjusted to reduce the likelihood of reoccurrence. Examples of maintenance programme adjustments include a programme of re-termination of cables on Magnefix units installed prior to 1975, installation of plastic dust covers on the auxiliary contacts of zone substation Reyrolle LMT circuit breakers, and post fault line patrols and inspections of “no fault found” outages.

Controlled events that can impact on network performance are planned network operations, or network equipment faults. Uncontrolled events are third party damage incidents, animal/bird interference, lightning strikes and vegetation contact outside controlled zones. A detailed analysis of data from the last five years provides the following breakdown between controlled and uncontrolled events which have impacted on SAIDI performance:

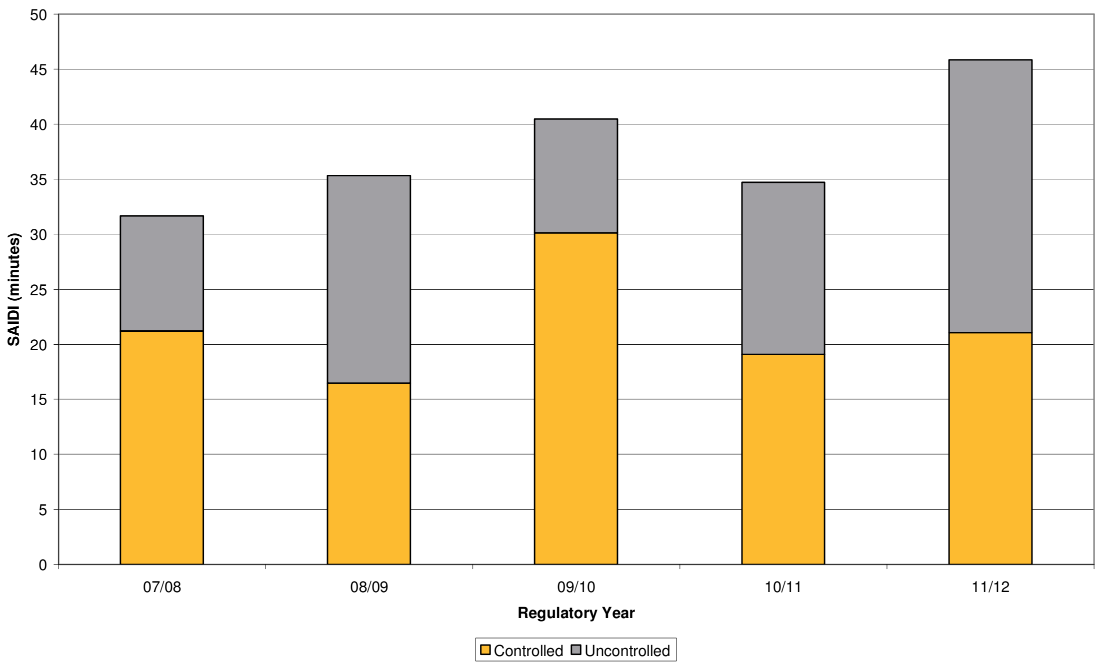

Figure 7-5 Summary of Controlled and Uncontrolled Events Impacting SAIDI Performance 2007-2012

In comparison to the 2009/2010 network performance, controlled events were significantly reduced in 2010/11 and maintained at a similar level in 2011/2012. The main area of focus was overhead network component failures which contributed 18 SAIDI minutes in the 2009/10 period. Improved inspection and condition assessment, as well as two large overhead rebuild projects, have led to this reduction to around 6 SAIDI minutes in this last period. This indicates that the corrective actions carried out to improve controlled events are effective and these activities will be continued in areas where asset performance is below average. The affect of uncontrolled events on SAIDI minutes has continued to rise since a low point in 2009/2010. Some uncontrolled events could be reduced using engineering design (such as undergrounding of lines), however the cost/benefit trade-off needs to be considered and in most cases would be found to be uneconomic.

Network pole damaged following a car vs. pole incident

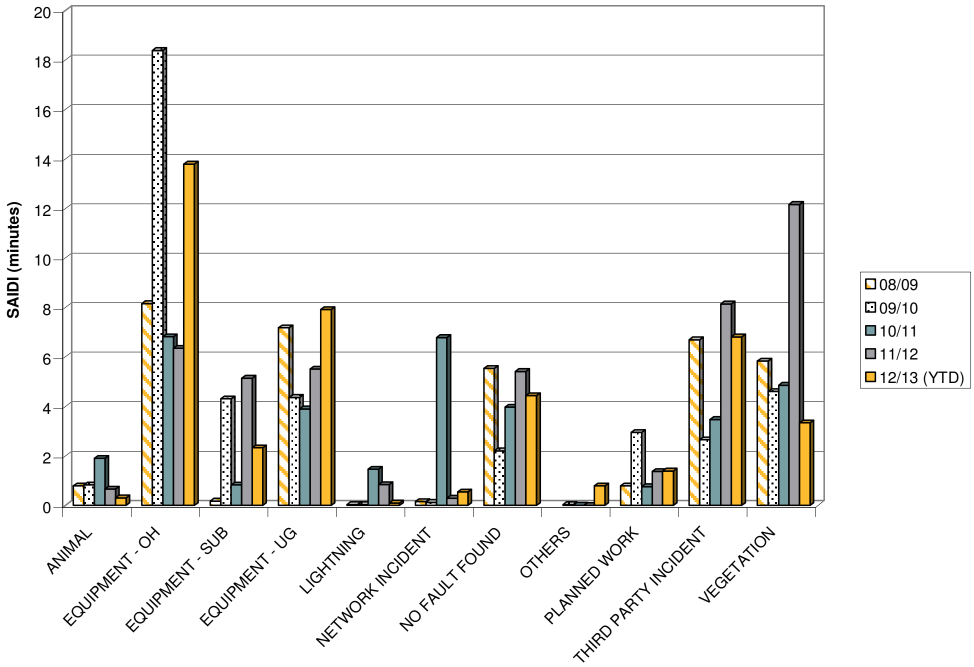

Figure 7-6 Five Year Historical SAIDI per Fault Type 2008-2013 (YTD)

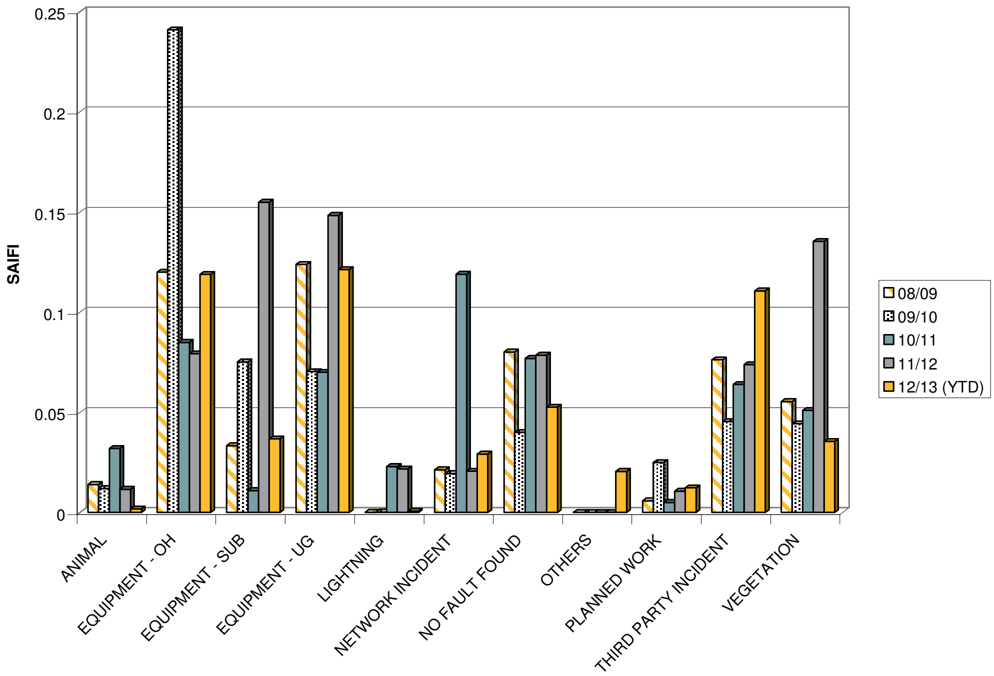

Figure 7-7 Five Year Historical SAIFI per Fault Type 2008-2013 (YTD)

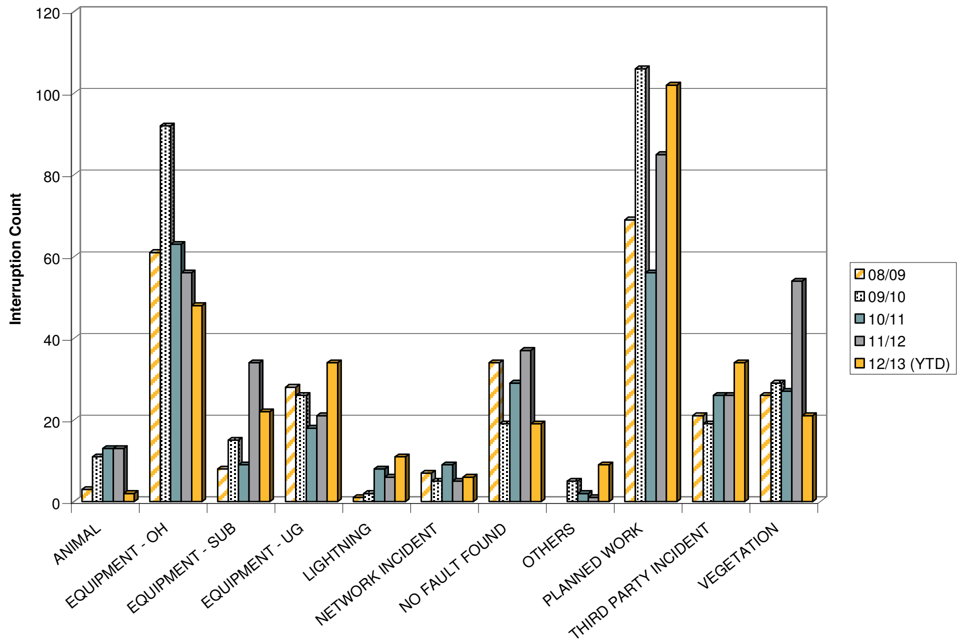

Figure 7-8 Five Year Historical Count per Fault Type 2008-2013 (YTD)

The five year historical reliability index charts show improvements in most of the fault types in the current regulatory period. The increase in the SAIDI of overhead equipment fault type was due to a one off incident in Trentham zone substation. This incident is explained in Section 7.1.2.1 Summary of Fault Causes 2012/13. Also, the increase in the equipment underground fault type count indicates that the condition of the cables must be assessed thoroughly and programme cable replacement in the future.

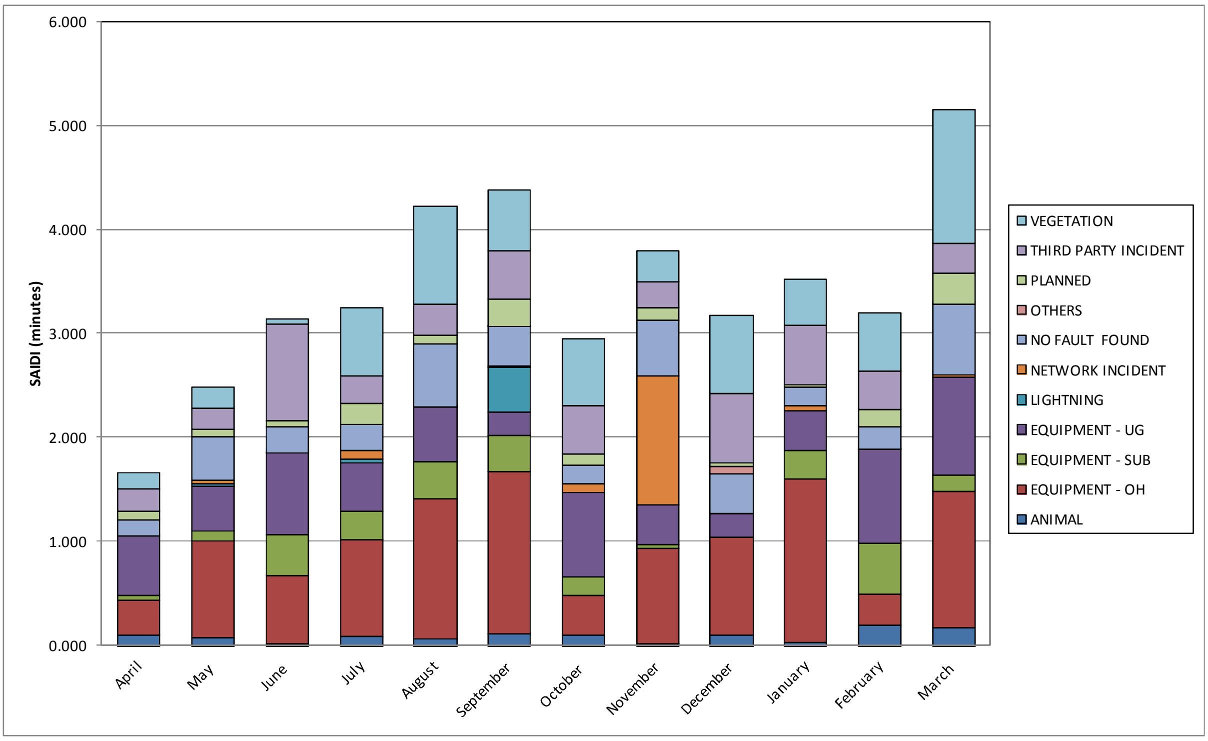

Figure 7-9 Five Year SAIDI Rolling Average per Month per Fault Type

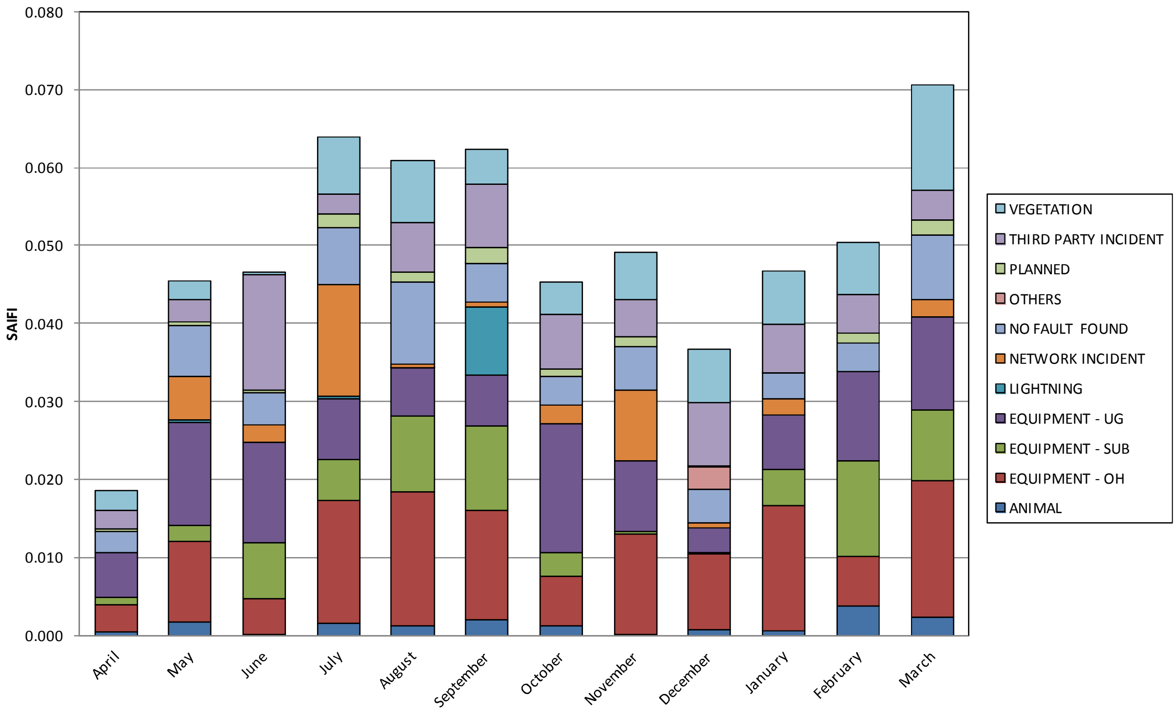

Figure 7-10 Five Year SAIFI Rolling Average per Month per Fault Type

Figures 7.9 and 7.10 show that the reliability indicators are high at the end of winter leading into spring and the beginning of autumn, predominantly in the Equipment-Overhead category. This identifies that environmental factors have a significant impact upon network performance whilst other factors remain steady during the year. Other fault types do not show clear trends and occur without pattern.

7.3. Industry Comparison

The reliability of the Wellington Electricity network is the highest amongst all Electricity Lines Businesses (ELBs) in New Zealand for the year 2011/12. The data presented in Figures 7.11 and 7.12 has been sourced from annual Information Disclosures made by Lines Businesses and made publically available..

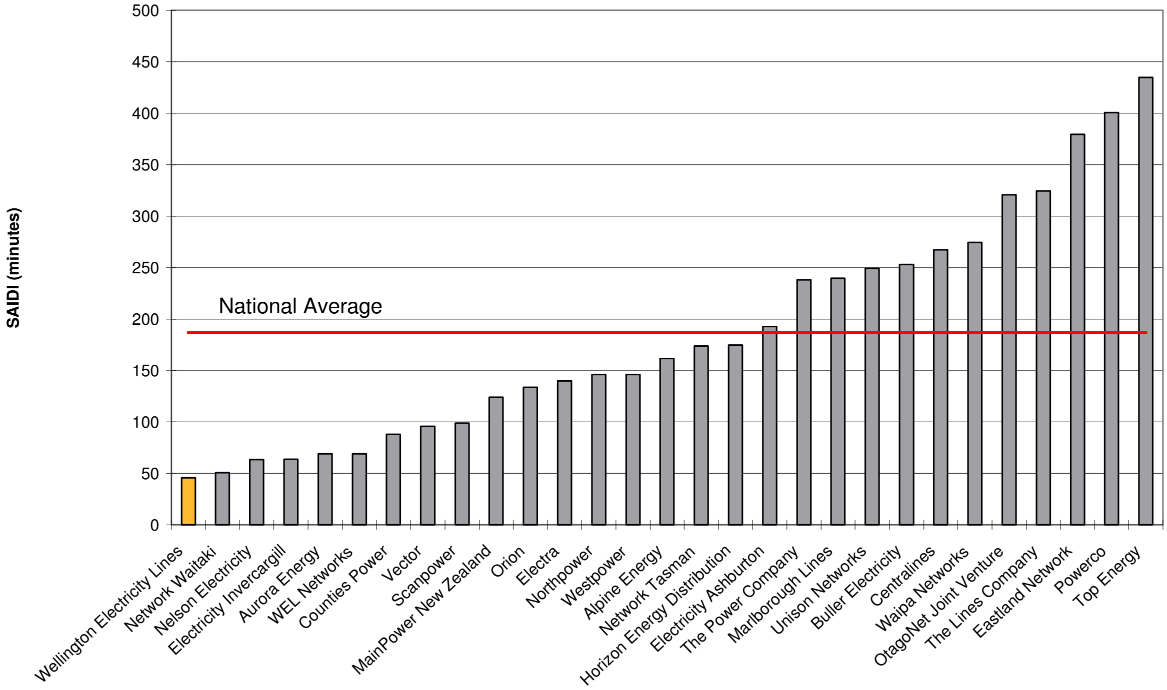

Figure 7-11 National SAIDI by ELB for 2011-12

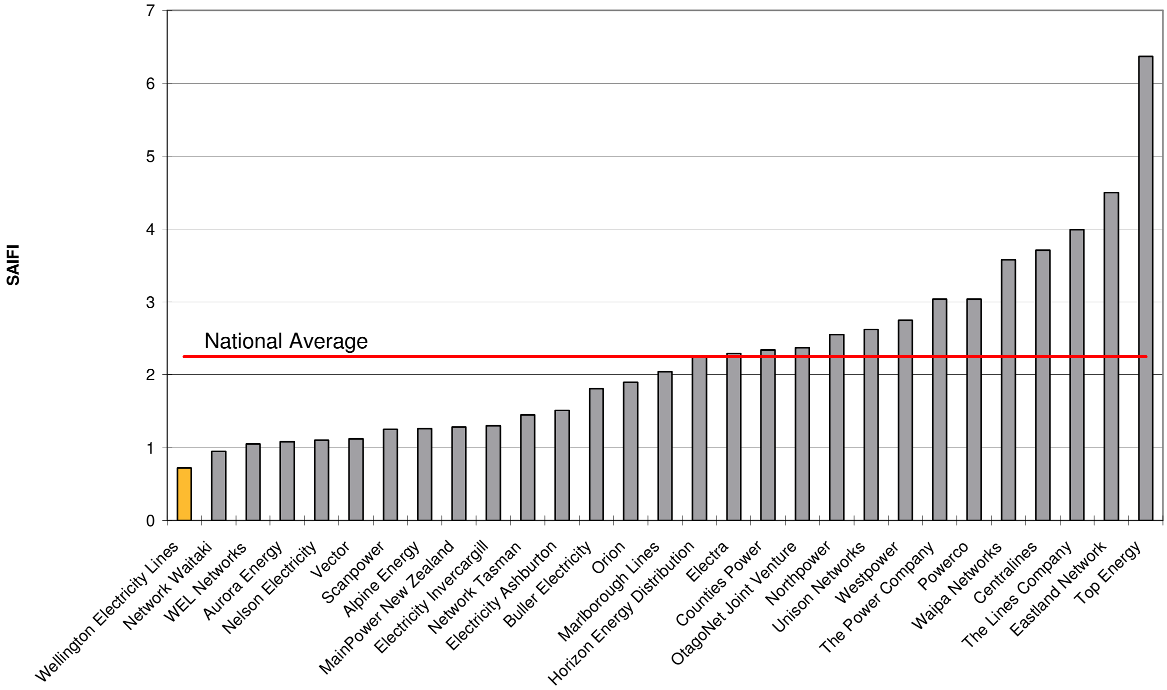

Figure 7-12 National SAIFI by ELB for 2011-12

This illustrates that consumers in the Wellington area enjoy a reliable network that provides the best level of performance compared with other networks in New Zealand.

Consumer satisfaction with the quality of supply delivered by Wellington Electricity is supported by a bi-annual survey, last carried out in late 2011. This survey concluded that consumers:

- Regard continuity ("keeping the power on") and restoration ("getting the power back on") as the first and second most important components of electricity line services
- Regard Wellington Electricity's performance in regard to continuity and restoration as either excellent or very good.

7.3.1 Benchmarking Analysis

Wellington Electricity has undertaken a benchmarking analysis of System Reliability Performance indicators within a peer group of comparable ELBs in New Zealand. The following criteria have been applied to establish a comparison using the data from ELB's Regulatory Year 2011/2012 Information Disclosures:

- Connection points of over the national average of 64,875 customers
- Connection point density of over the national average of 13 ICP/km
- Percentage circuit length underground of over the national average of 25.4 %

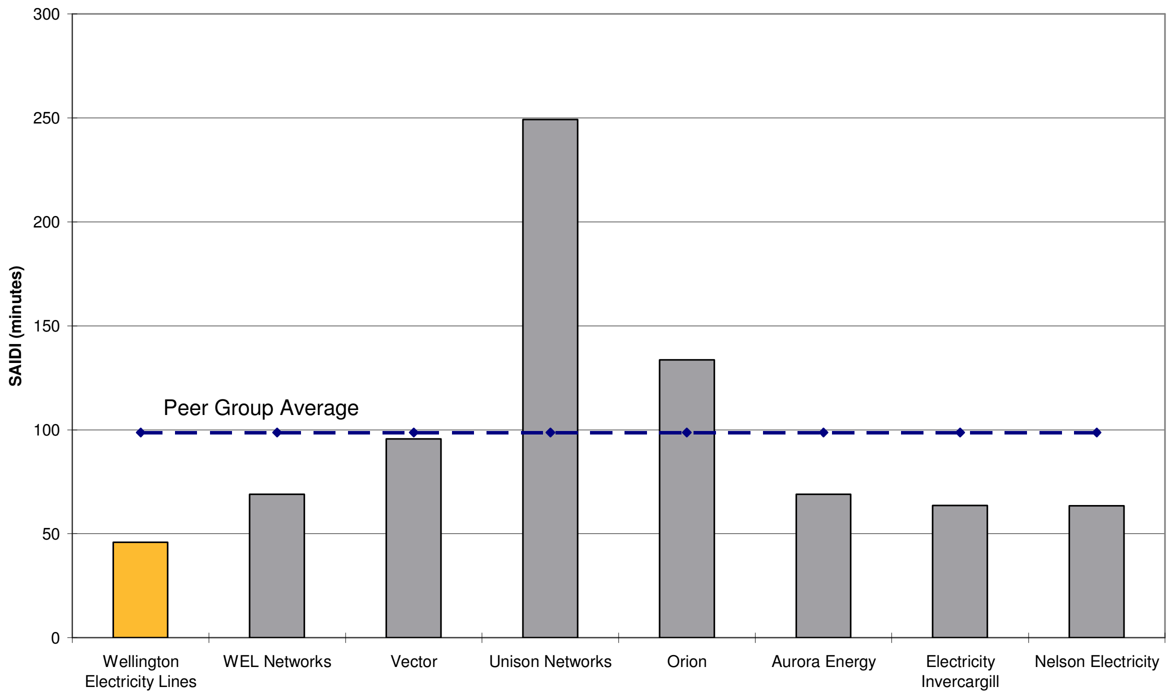

Figure 7-13 Peer Group SAIDI Comparison 2011/2012

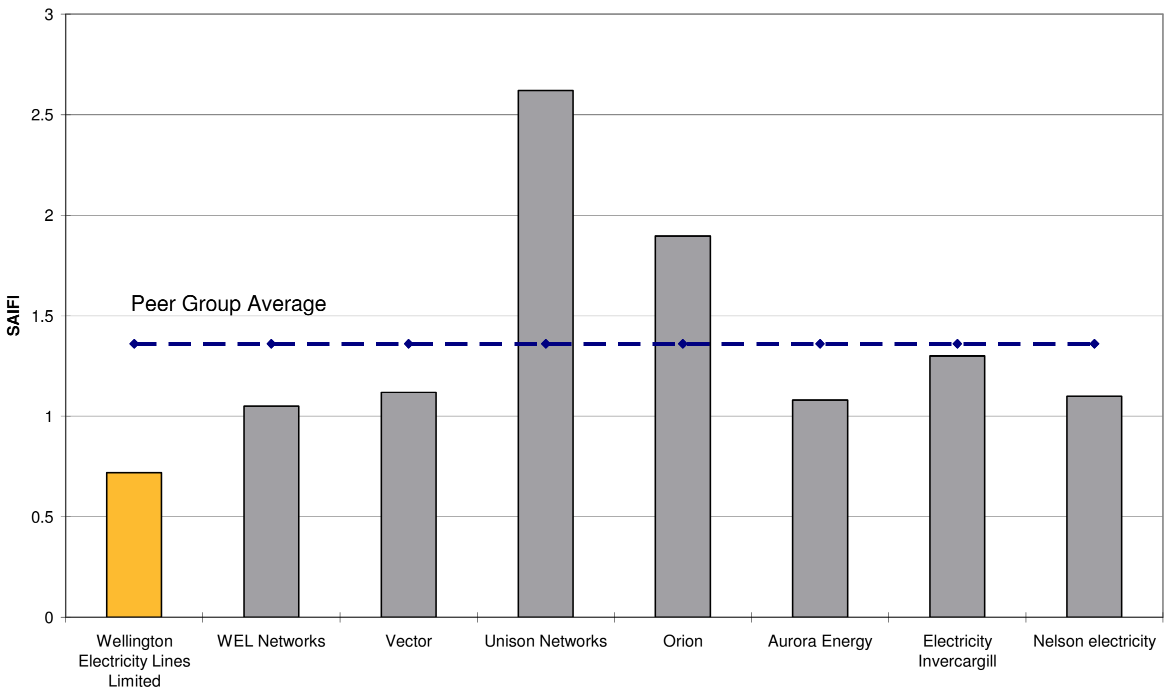

Figure 7-14 Peer Group SAIFI Comparison 2011/2012

The benchmarking analysis shows that Wellington Electricity's system reliability index (i.e. SAIDI, SAIFI) are in the upper quartile of the peer group. This supports the claim that Wellington Electricity is currently performing well above comparable networks in New Zealand.

7.4. Network Reliability Performance (2012/2013 Year to Date)

The Wellington network performance for 11 months of the 2012/2013 regulatory year is tracking over the Year to Date (YTD) targets of 37.345 minutes for SAIDI and 0.550 for SAIDI. Another severe weather event (extreme winds for 17 hours) on 8 September 2012 significantly affected the network and triggered the declaration of a major event response for Wellington Electricity. Once again multiple outages were caused by due trees and wind borne debris being blown into the overhead network, damaging assets and interrupting supply.

The largest single outage was the Trentham Zone Substation which suffered shorting across the protection communications cable and the 33kV line, damaging isolation equipment at each end and causing both 33kV lines to trip out. As a result of this outage, 4,870 customers were affected for several hours whilst the protection fault was identified and repaired to a level to allow the subtransmission supply to be restored. This protection arrangement was improved immediately following the fault, and will be reviewed in 2013 with reconfiguration undertaken to reduce the likelihood in the future.

Approximately 7,300 customers were affected with the majority of faults were in rural areas and restoration delayed by safety concerns for responding crews. While the SAIDI impact of this event was over 8 minutes, it does not qualify as a "major event day" for the purpose of replacing the actual SAIDI value with a boundary value. Two days after this event, a landowner felled trees into the remaining Trentham 33kV circuit causing a second major outage at this substation as one circuit was left out of service due to the earlier protection fault.

7.4.1 Summary of Fault Causes

The summary SAIDI and SAIFI by fault cause is described below. "Equipment – OH" as a fault cause has the highest impact on SAIDI largely due to the September 2012 storm. The most significant event during this storm was the total outage at Trentham zone substation which resulted in the loss of over 5 SAIDI minutes.

<u>Overhead Equipment</u>

Overhead equipment failures outages were mostly related to days of strong winds or stormy weather. Following overhead faults, the condition of overhead conductors is observed during routine inspections, although fatigue is not always visible. Increased focus is being applied to identify suspect connector types on the overhead network, such as Fargo automatic line splices which have been found to fail during strong winds and hence are being progressively replaced.

<u>Underground Equipment</u>

Underground equipment failures were due to cable and cable joint failures. Cable systems are expected to have a long life with high reliability as they are subject to fewer environmental hazards. However as the systems age performance is seen to decrease. External influences such as third party strikes, inadvertent overloading, or even unusual high loading within normal "design limits" can lead to shortening of the service life of cable systems. To minimise possible failures, vulnerable sections of cable are identified using diagnostic tests (such as insulation resistance, VLF and partial discharge) and proactively replaced.

<u>Third Party Incidents</u>

The third party incidents contributed 6.5 SAIDI minutes and were due to excavation works and vehicle collisions. The Ultrafast Broadband (UFB) network project has had a significant impact on the number of third party strikes due to the number of dig-in incidents as Chorus contractors install the cable.

One example of such an incident is the two locations where cable strikes occurred in the same area of Churton Park on the same day. This affected 1,979 Wellington Electricity customers who were without power for over three hours. Wellington Electricity management has met with Chorus management to highlight the effect of these cable strikes to the network.

<u>Vegetation</u>

Vegetation related outages are generally due to trees not being trimmed by landowners. Wellington Electricity has largely completed the (free) first cut and trim process and the trees are now the responsibility of landowners under the Electricity (Hazards from Trees) Regulations 2003. Wellington Electricity and Treescape (vegetation management contractor) are working with landowners and TLAs to address the issue of vegetation management.

<u>Substation Equipment</u>

Substation equipment failure is largely attributed to one significant outage when a distribution substation caught on fire due to a cable overload during planned work. The network was in an abnormal state due to several feeders being tied together which amplified the SAIDI and SAIFI impact. Improved controls have been put in place to manage abnormal system loadings during planned works.

No Fault Found

Most of the incidents related to the “no fault found” cause occurred during stormy weather and are most likely to result from vegetation or line clash transient events. These feeders were subsequently patrolled to identify any areas where improvements can be made to the network.

7.5. Asset Management Focus Areas (2011/12)

Asset management focus areas are identified through trend analysis of data from previous years with the current year to date (YTD) information included for reference. Where trends are identified, targeted asset management strategies can be implemented. This section provides discussion on initiatives undertaken in the past years and the effect they have had on network performance.

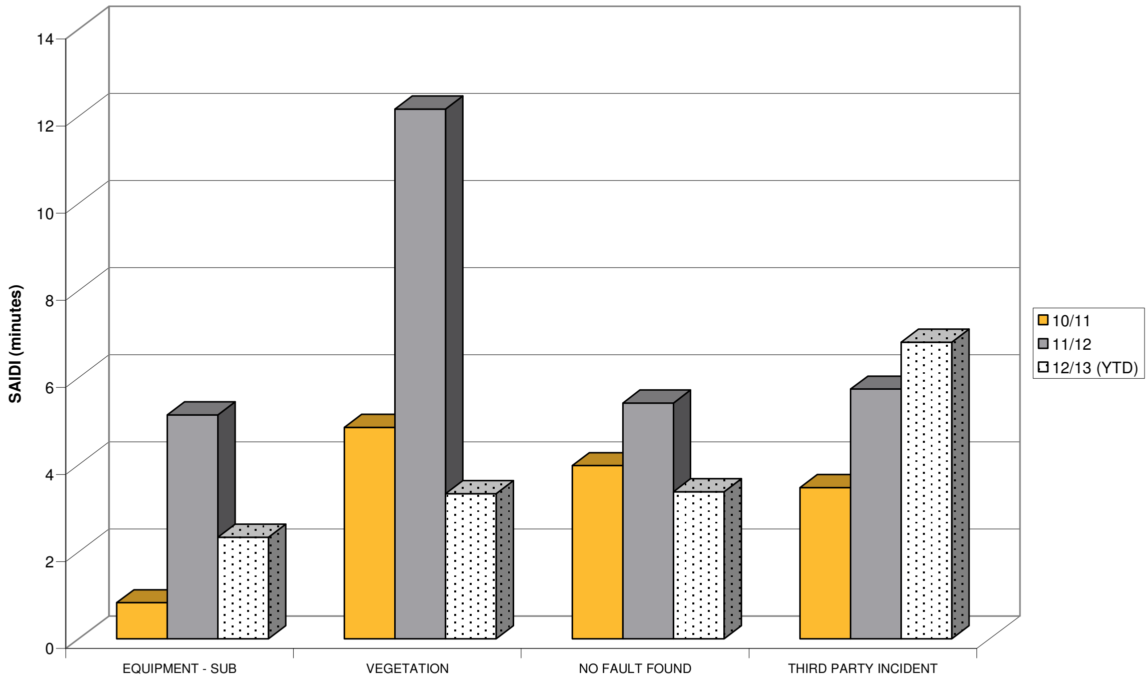

Figure 7-17 SAIDI by Asset Management Focus Areas

Substation equipment issues, particularly the failure of LMT Reyrolle switchgear to operate under fault conditions (due to auxiliary switch issues), were the focus area in 2011/2012. The maintenance carried out on this switchgear type has shown significant improvement in rates of substation equipment failure.

With regard to vegetation management, Treescape has continually made contact with the owners of the trees which are encroaching upon, and presenting potential hazards to, overhead lines. As detailed above, there are tree owners who have been reluctant to meet their obligations under the tree regulations.

‘No fault found’ outages usually occur on overhead feeders with the most common causes being tree branches touching lines during stormy weather, debris falling on the line and then clearing, as well as bird strikes. For every fault classified as a ‘no fault found’ cause, a line patrol is carried out at the earliest opportunity to investigate the fault, and to identify possible causes. Feeders with recurring ‘no fault found’ outages are subject to more thorough, targeted inspection regimes which may lead to corrective maintenance or replacement activities.

Wellington Electricity has commenced further education of the public regarding the hazards of power lines and risks to network assets. Radio advertising is being targeted at the key causes of third party incidents such as vehicle contact, overhead line contact, and promoting the 'dial before you dig' service (specifically to reduce the number of underground cable strikes).

7.5.1 Maintenance Activities

Both planned and corrective maintenance activities are being undertaken on a targeted basis to address identified reliability problems. Examples include improved condition assessment of overhead lines and components, and more regular maintenance of substation protection and circuit breakers to ensure correct operations. Where practicable, certain asset types are being replaced to address known performance issues. This strategy will help to maintain reliability through improved equipment condition and performance. The costs associated with these programmes will increase over time. Unfortunately, with tight regulatory control over business revenue, there is limited scope to recover significant increases in costs associated with increased maintenance and asset replacement activities.

7.5.2 Maintenance and Inspection Standards

Wellington Electricity has reviewed and improved upon previous maintenance standards and practices on its network, including condition assessment and asset information capture. By improving the inspection process, and through better analysis of data, investment and maintenance can be better focussed. For example, Wellington Electricity will be conducting a detailed survey of overhead lines and components in high wind areas to see whether their integrity is sufficient to meet the higher wind loads experienced.

7.5.3 Worst Performing Feeders

The method used to determine the worst performing feeders for 2011/2012 regulatory period was a different approach than the 2010/2011 period which was based upon the feeder performance over a five year period. There were three categories considered, SAIDI, SAIFI and the number of interruptions a feeder experiences in a year. The top ten feeders from each category were subjected to more intense scrutiny. Determining which feeders were the "worst performing" was based on whether a feeder was featured in each of the three categories, or if the feeder performance had deteriorated in the last regulatory period in any of the three categories.

In 2011/2012, the performance of each feeder (from 1 April 2011 – 31 March 2012) was compared to the previous two years. Any significant increase in SAIDI and SAIFI or the number of interruptions meant a feeder was included in the list.

The worst performing feeders in 2011/2012 were identified as Brown Owl 8 (BRO 8), Brown Owl 3 (BRO 3), Maidstone 10 (MAI 10), Trentham 8 (TRE 8), Gracefield 2 (GRA 2), and Plimmerton 8 (PLI 8). Reliability improvements and corrective maintenance programmes were carried out on these feeders and the results of improvements are notable as shown in the graphs below.

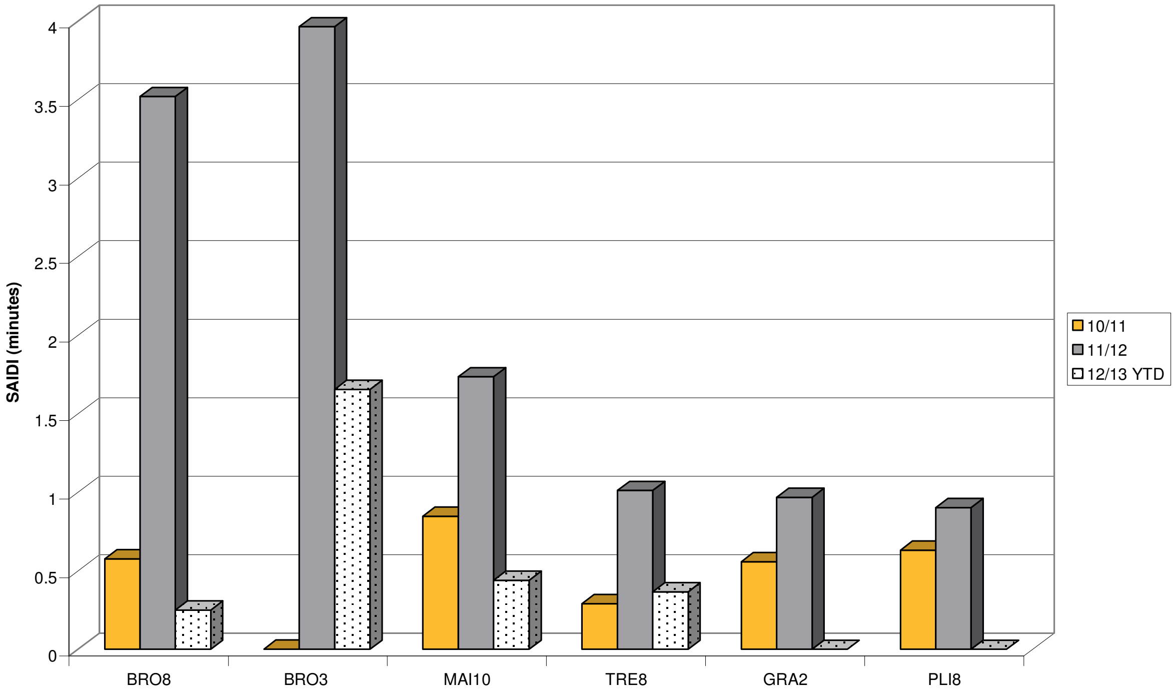

Figure 7-18 Worst Performing Feeders (2011/12 with 2012/13 YTD) - SAIDI

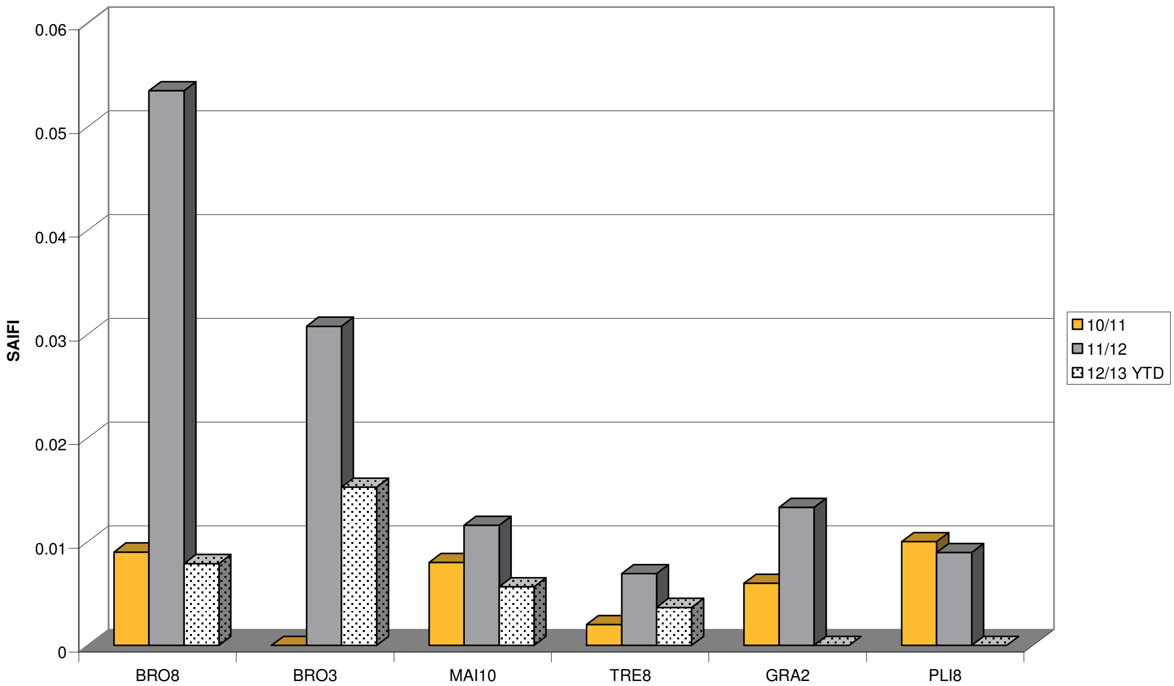

Figure 7-19 Worst Performing Feeders (2011/12 with 2012/13 YTD) - SAIFI

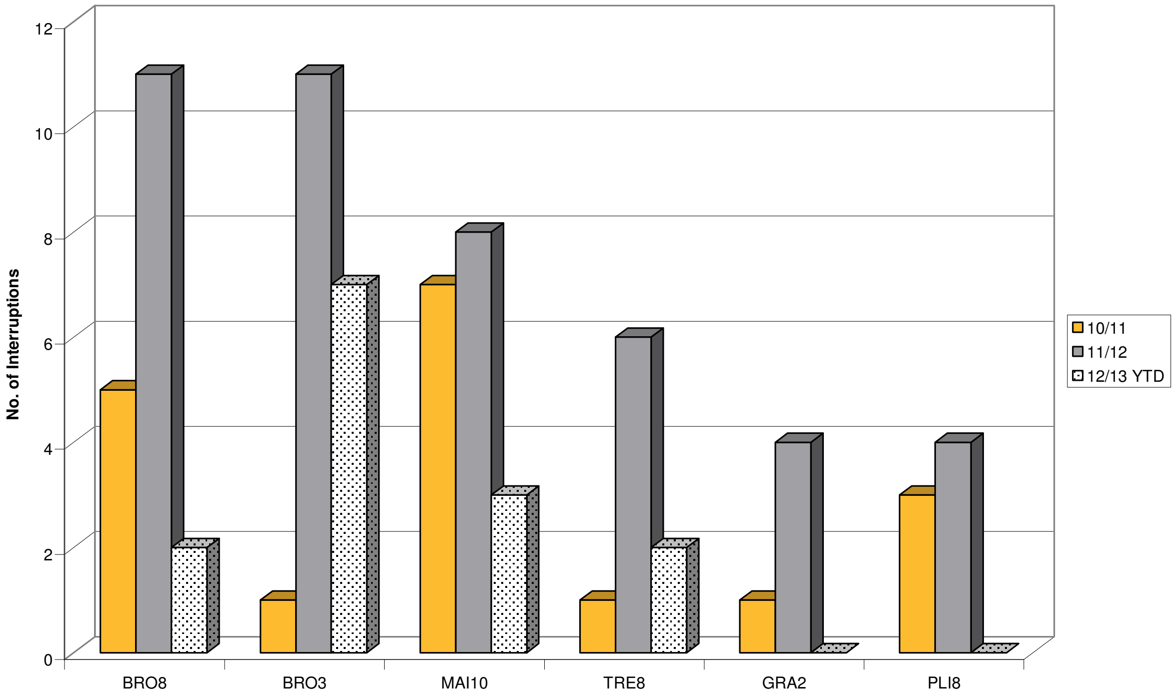

Figure 7-20 Worst Performing Feeders (2011/12 with 2012/13 YTD) by Number of Interruptions

Although the worst performing feeders identified last year have improved in terms of SAIDI and SAIFI, increased reliability programmes previously identified will still be carried out to ensure there is no decline in performance.

The method used to determine the worst performing feeders for 2012/2013 was similar to the approach of the previous period. The current performance of each feeder (from 1 March 2012 – to date) was compared to the previous two years. Any significant increase in SAIDI and SAIFI or the number of interruptions meant a feeder was included in the list. The identified worst performing feeders (since the beginning of the 2012/2013) were grouped as follows:

- Feeders with high SAIDI and SAIFI and 4 or more interruptions: Melling 7 (MEL7), Brown Owl 3 (BRO 3), Naenae 6 (NAE6), Wainuiomata 3 (WAI3)
- Feeders showing significant increase in SAIDI or SAIFI with 3 or more outages: Wainuiomata 12 (WAI12), Waitangirua 11 (WAN11)

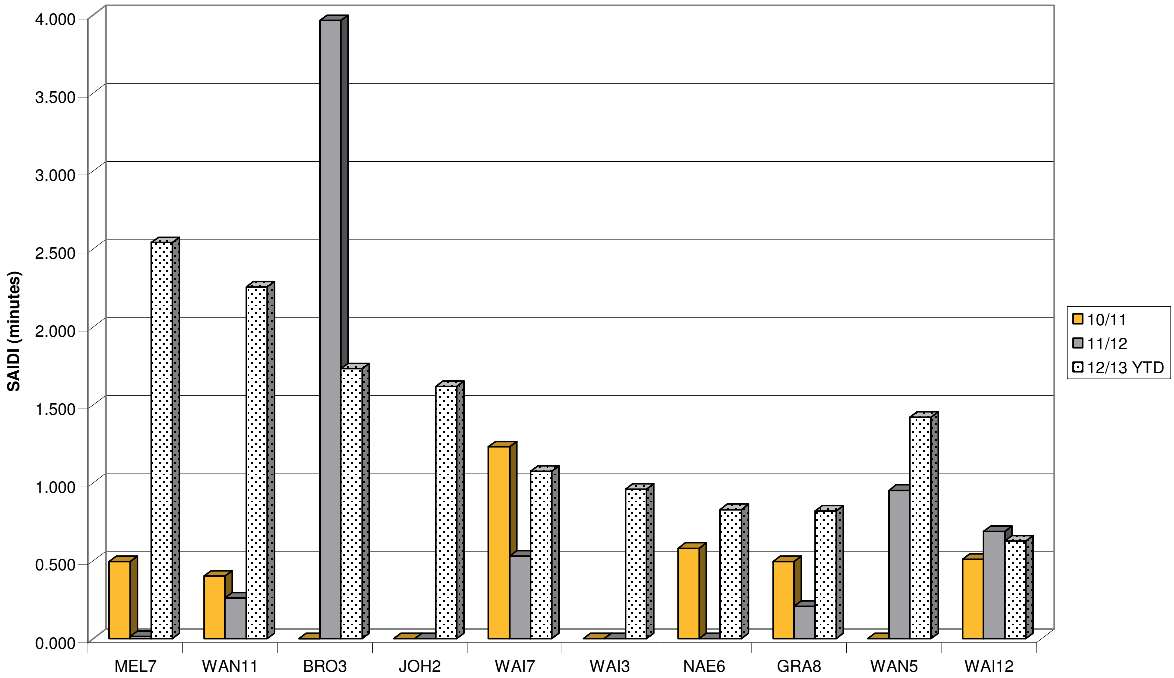

Figure 7-21 SAIDI of Worst Performing Feeders (2012/2013 YTD)

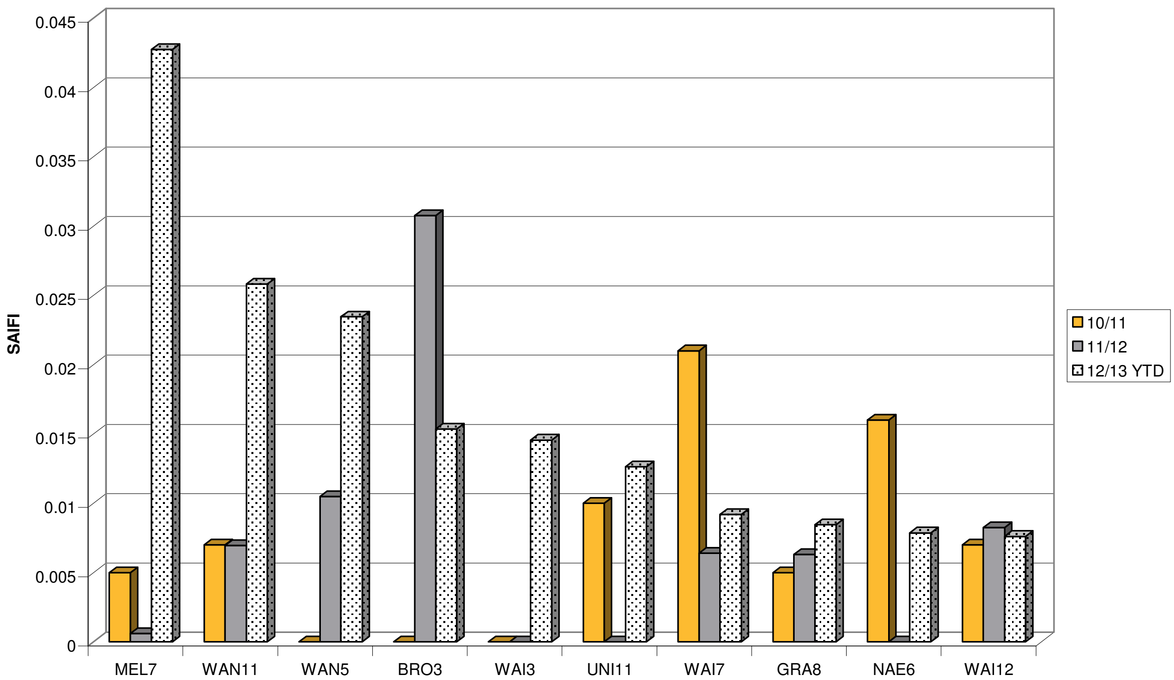

Figure 7-22 SAIFI of Worst Performing Feeders (2012/2013 YTD)

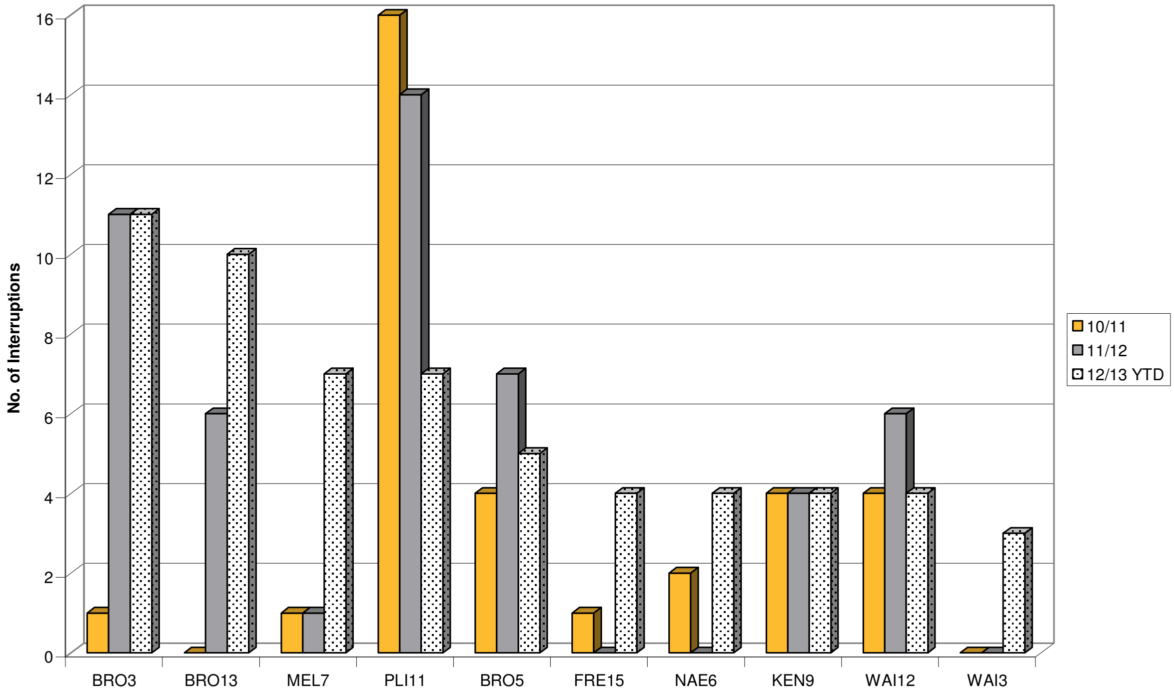

Figure 7-23 Interruption Count of Worst Performing Feeders (2010-2013 YTD)

In summary, the worst performing feeders for 2012/2013 are:

Feeder	2012-2013 YTD Performance		
	SAIDI	SAIFI	No. of Interruptions
Melling 7	2.541	0.043	7
Waitangirua 11	2.25	0.026	5
Brown Owl 3	1.73	0.016	13
Wainuiomata 3	0.96	0.015	3
Naenae 6	0.83	0.008	4
Wainuiomata 12	0.63	0.006	4

Figure 7-24 Worst Performing Feeders for 2012/13

Historic faults on these feeders are reviewed to determine if there is a common root cause that needs to be addressed. Remedial actions identified as part of this review are fed back into the maintenance process where the resulting activities are carried out either under corrective maintenance (OPEX), or as a network project (CAPEX), depending on the scope of the work required. It should be noted that although these are the "worst performing feeders" on the Wellington Electricity network, the worst feeder contributes less than 5% to the total annual SAIDI and SAIFI results.

7.5.4 Reliability Improvement Programme

Melling 7

Melling 7 is mostly underground (around the area of Lower Hutt and Woburn) and there are 1,488 customers connected to this feeder. Most of the faults recorded on this feeder were cable joint faults in between Melling CB7 and Andrews Avenue substation CB5. The cable was installed in 1957 with sections replaced over subsequent years. This cable has been subjected to third party strikes and is also suspected to have been stressed due to through faults in recent years. Wellington Electricity intends to replace a section of this cable with high numbers of joints, and will consider further diagnostic tests to identify any areas with declining insulation performance or joint fatigue. This will assist with identifying sections of the cable to replace to improve the reliability in this area.

Waitangirua 11

Waitangirua feeder 11 is a fully underground feeder in the area of Ascot Park and Whitby West with 1,253 customers connected to it. The two cable faults which occurred on the feeder in the past year are not conclusive evidence that the feeder's reliability is declining as there was no common link between them. The underground cable was installed in 1975 and is expected to be reliable for a longer period of time. Similarly to Melling 7, cable diagnostic tests will be used to identify areas of cable with declining insulation performance to understand whether further failures are likely and whether cable replacement is required. Performance on this feeder since the two faults has been acceptable and the situation will be monitored.

Brown Owl 3

Brown Owl feeder 3 is a combination of underground cables and overhead lines. It has 1,009 customers connected to it. The overhead line supplies customers in Akatarawa Road which is heavily forested. Most of the faults on this feeder have been due to trees on the line. Although this feeder was one of the worst performing feeders in 2011/2012, due to snow and broken branches contacting lines, performance has improved this year because of improved weather. Brown Owl will remain as a priority feeder under watch by Wellington Electricity and Treescape but we are unlikely to clear for snow damage separation as this is uneconomic and unlikely to occur again in the near future.

Wainuiomata 3

Wainuiomata feeder 3 is mostly underground in the Parkway area of Wainuiomata with 808 customers. Similarly to Waitangirua 11, there were two cable faults on the feeder during the year for which no conclusive cause was identified.

Naenae 6

Naenae feeder 6 is mostly overhead network and serves 1,227 customers in the areas of Avalon and Taita. The feeder had one incident of overhead equipment failure when a crossarm failed and three incidents of lightning strikes which occurred on the same day at different locations. The feeder was thoroughly inspected and corrective actions were carried out to ensure reliability can be maintained. Although this feeder scored high in this assessment period, it may not feature next year if performance is found to be acceptable.

Wainuiomata 12

Wainuiomata feeder 12 is mostly overhead lines in Moores Valley Road with 851 customers. Two out of the three outages of this feeder were due to trees on the line. This feeder is on the priority list under watch by Wellington Electricity and Treescape.

Crossarm replacement in Wainuiomata

7.5.5 Other Reliability Initiatives

All overhead feeders are subject to an annual inspection and other network equipment is inspected and maintained at prescribed intervals. Other initiatives to improve the speed and accuracy of fault finding and restoration include:

Fault Passage Indicators

Line fault indicators are used widely on the overhead network and earth fault indicators are used on the underground network. These aid in the identification of faulty sections of the network and are particularly useful in areas that are difficult to access or where long outgoing feeders have many spur lines and tee points.

Line Circuit Breakers / Autoreclosers

Auto reclosers are used on most rural feeders to provide a fast, automated reclose function to clear transient faults such as bird strike, vegetation or line clashes in stormy weather. The use of automatic reclosers in strategic areas of the network also reduces the number of customers affected in the event of a permanent fault on that feeder.

Remote controlled overhead switches

Remote overhead switches are used to enable remote operation of the network by the Network Control Room, in conjunction with a faultman on the ground, to improve isolation and restoration times.

Removing equipment with operational restrictions

Across the network there are types of equipment with fault operation restrictions, in particular Yorkshire SO-HI switchgear. Being unable to operate these assets increases fault identification and response times. Replacement of SO-HI is underway, with equipment on high SAIDI feeders being the priority.

Overhead line refurbishments

Starting in 2010, strong focus is being put on the maintenance of overhead lines, particularly on the worst performing feeders of the network. Ngauranga feeder 4, for example, had previously been the top worst performing feeder. In response, the feeder was subject to a more detailed inspection and an overhead line refurbishment was carried out on the section of the feeder which has the most number of faults in the last five years. This refurbishment included replacement of conductor, cross arms, insulators and other line hardware. The overhead line improvements were also applied to Korokoro feeder 9 which has experienced a dramatic increase in reliability.

Overhead line refurbishment is a continuous programme of Wellington Electricity. Two other feeders, Wainuiomata 7 (Coast Road) and Karori 2 (Makara) were on the list of worst performing feeders and are currently undergoing line refurbishments. These will be carried out in stages over the next 10 years. Stage one for both feeders commenced in 2012 and is expected to be completed in 2022. These programmes have started with the worst performing sections, progressing through to the most reliable sections.

Another line refurbishment that will commence in 2013 will be Ngauranga 9 which will be completed in one year. As performance is found to deteriorate in other parts of the network, these will be considered for refurbishment.

Installation of SCADA indication and control on distribution substations

In some areas, the installation of SCADA indication and control on selected distribution substations will improve the restoration time of a faulted section of a feeder. These would be installed on distribution substations on feeders with high numbers of customers, separated by circuit breakers with protection relays (a legacy design of the Wellington Electricity network). This will provide for faster restoration of supply that can be backfed from another feeder following identification of the faulted network area. Network analysis is in progress as to where the installation of SCADA indication and control on distribution substations will be beneficial and cost effective. Examples are Normandale Bridge, Melling Railway and Churton Park substations which will be considered in the 2013 and 2014 programmes for Protection and Control. These improvements will be considered following the identification of root cause issues to reduce fault occurrences, and also operational improvements to reduce response time.

8 Risk Management

8.1 Introduction

Risk management is an integral part of any business and therefore extends to the asset management process. The consequences and likelihood of failure, the performance of controls which are set to manage the identified risks need to be understood, reviewed and evaluated as part of the asset management function.

Risks associated with network assets are evaluated, prioritised and dealt with as part informing the principles and assumptions for setting the network development, asset maintenance, refurbishment and replacement programmes.

The controls for each risk are considered in developing standard work practices. The level of control to lower each risk to an acceptable level will differ depending upon the risk tolerance of key stakeholders and the circumstances and environment in which the risk may occur.

Risks controls associated with system assets are managed:

- Proactively - reducing the probability of asset failure through the capital and maintenance work programmes, insurance strategies and enhanced working practices
- Reactively - reducing the impact from a failure through business continuity planning and through the development of an efficient fault response capability.

High probability, low impact risks and conversely low probability, high impact risks are managed through a combination of Wellington Electricity's network planning and design, asset maintenance, fault response and emergency response strategies. Sections 5 and 6 of this AMP describe the network planning and asset maintenance strategies in some detail. In addition, Wellington Electricity's design standards, which are not described in detail in this AMP, are aligned with industry best practice and aim to take account of the weather and the seismic environment in the Wellington area. Further, Wellington Electricity has contingency procedures in place to restore power in a timely manner should an asset failure cause a supply interruption.

While it is impractical and uneconomic to design an electricity network that is immune to all risks, low probability, high impact events can occur that are either outside the network design envelope or require a response that is beyond the normal capacity of Wellington Electricity and its service providers. For such events Emergency Response Plans have been adopted and these are detailed later in this section.

8.2 Risk Accountability and Authority

Wellington Electricity's Board of Directors provides governance for the business risk management, reporting as a part of its corporate responsibility via the Audit and Risk Committee. The Audit and Risk Committee are updated biannually by the business as part of regular management reporting functions in line with the risk reporting framework.

Wellington Electricity's Senior Management Team (SMT) monitors the effectiveness of the risk controls providing a report for the CEO to present to the Directors. Each individual risk control is allocated to a Manager as the risk control owner. The risk control owner is responsible for ensuring that the control for each risk is clearly understood within the business and the risk controls are effective. Each risk control owner monitors the risk control and contributes towards the risk reporting framework.

In developing and implementing its risk management strategy, the CEO meets with senior management regularly to review business risks and controls. Strategic and operational risks categories are reviewed and reported in a risk register while more detailed operational risks are captured in risk control procedures and processes. The risk management strategy and process is aligned with other CKI group companies ensuring consistency across the wider global business.

8.3 Risk Framework

Wellington Electricity adopts the Risk Management Standard ISO31000:2009 to provide a structured and robust methodology to managing risk. The risk framework provides a process for:

- Identification of the risk event, assessment of the potential causes and possible consequences of the event and quantification of the likelihood and consequence ratings to determine the inherent and residual risk ratings for the event.
- Identification of risk controls and assessment of the effectiveness and reliance of these controls to reduce or mitigate the risk – this generates the residual risk rating.
- Development of risk treatment plans to address unacceptable residual risk (high and extreme risks) or allow the business to accept a high risk activity.
- Creation of a risk register to capture the above information.

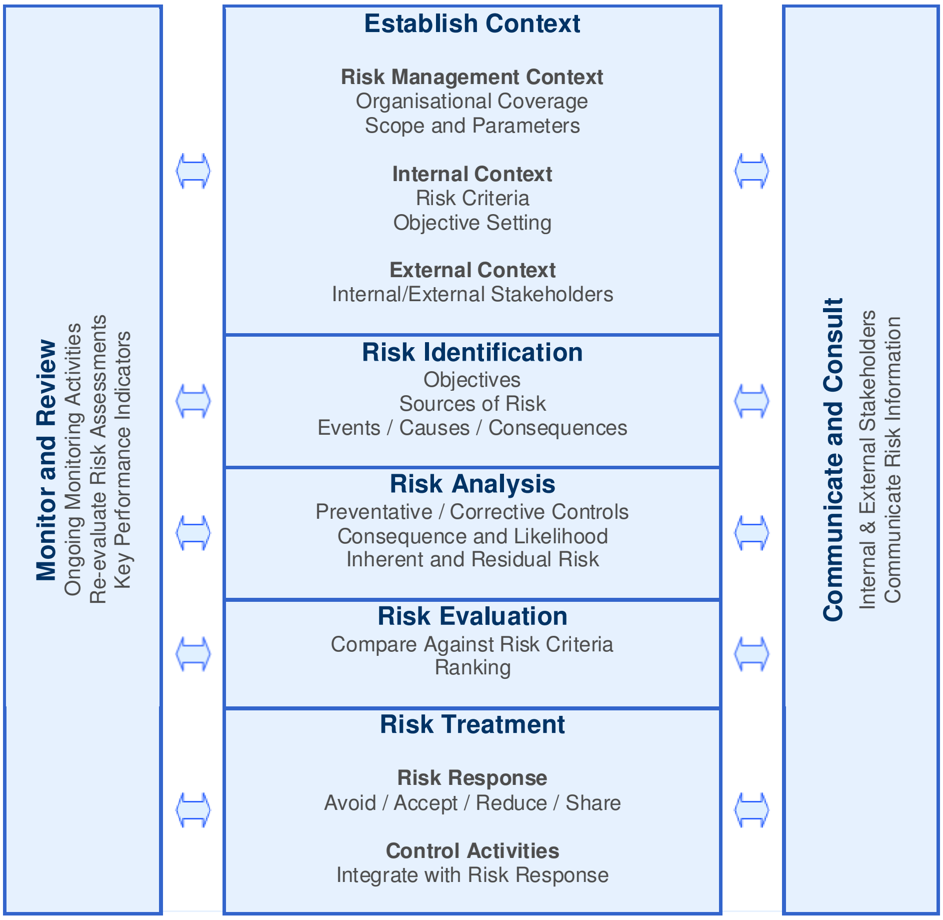

Figure 8-1 Risk Assessment Process

The objective of the risk treatment plan is to improve the control environment and to reduce any high residual risk as far as practicable. Appropriate risk treatment plans are developed as required, assigned to business risk owners and monitored to ensure that the business is taking proactive steps to mitigate the risk. These plans include a basic cost analysis to assess the practicability of the improvement options for existing controls and/or additional control initiatives to further reduce the risk to an acceptable level.

8.4 Risk Rating

The magnitude of the consequences of a possible risk event needs to be based on the ***most likely or most realistic*** impact on the business and its stakeholders. The following risk profiling matrix is used to determine the level of the risk or risk rating based on a function of consequence and likelihood.

LIKELIHOOD	CONSEQUENCE				
	Minimal	Minor	Moderate	Major	Catastrophic
Almost Certain	Medium	High	High	Extreme	Extreme
Likely	Low	Medium	High	High	Extreme
Possible	Low	Low	Medium	High	High
Unlikely	Negligible	Low	Low	Medium	High
Rare	Negligible	Negligible	Low	Medium	High

Figure 8-2 Levels of Risk Rating

Wellington Electricity uses the following consequence and likelihood criteria:

- Health & Safety (employees, public & service providers)
- Environment (land, vegetation, waterways & atmosphere)
- Financial (cash & earnings losses)
- Reputation (media coverage & stakeholders)
- Compliance (legislation, regulation & industry codes)
- Customer Service/Reliability (quality & satisfaction)
- Employee Satisfaction (engagement, motivation & morale)

The criterion is combined with a consequence scale, determining the level of consequence to the business of a particular risk ranging from minimal to catastrophic.

8.5 Risk Method Application

Controls are introduced to reduce/mitigate the likelihood or consequence of the risk with varying levels of effectiveness and reliance placed on the particular control. This helps reduce the inherent risk to a more acceptable residual risk.

Risk scoring is undertaken in accordance with the approved corporate Risk Policy which outlines quantitative measures by which Likelihood and Consequence can be ranked. The risk assessment model then assigns a weighted score in accordance with the ranking selected and the product of the Likelihood and the Consequence scores determines the overall risk score.

Risk score	Inherent Risk (Before Controls) 9500 / Extreme	Residual Risk (After Controls) 400 / High
Likelihood	95	25
	Almost Certain	Likely
Consequence	100	16

Risk score	Inherent Risk (Before Controls) 9500 / Extreme	Residual Risk (After Controls) 400 / High
Compliance	Major	Minor
Customer Service / Reliability	Major	Minor
Employee Satisfaction	Major	Minor
Environment	Moderate	Minimal
Financial	$1m to $5m	$100k to $500k
Health & Safety	Major	Moderate
Reputation	Major	Minor

Figure 8-3 Example of Risk Scoring

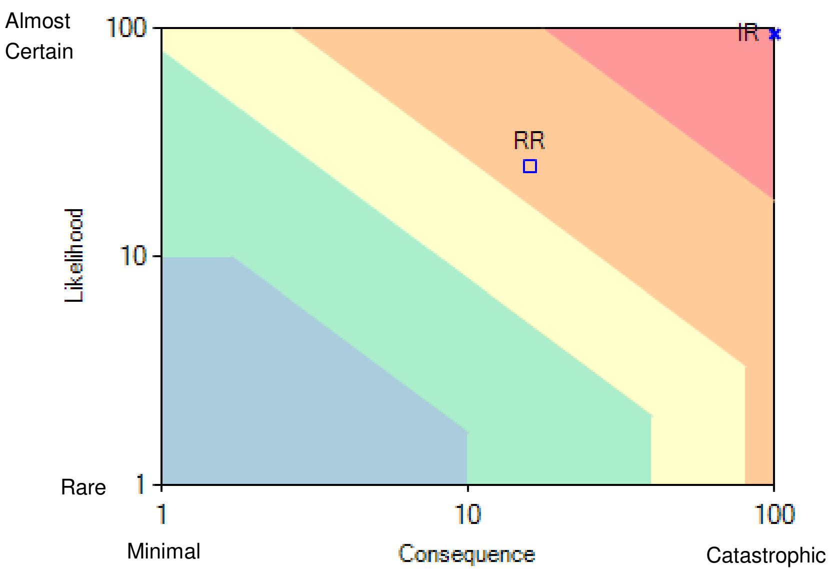

Figure 8-4 Example of Risk Methodology Application

8.6 Risk Application Example – Johnsonville Zone Reinforcement

8.6.1 Overview

As part of the ongoing analysis of network development planning it was evaluated that the subtransmission link between Transpower's Takapu Road Grid Exit Point (GXP) and Wellington Electricity's Johnsonville zone substation was not able to provide adequate capacity following an N-1 contingency event at times of high load. The N-1 capacity of the subtransmission link is constrained by the underground section of the circuit with a rating of 20 / 14.5 MVA (winter / summer). The peak load at Johnsonville zone substation is approximately 22 / 15 MVA (winter / summer) leading to a subtransmission N-1 shortfall in the order of 2 MVA for winter peaks. As part of the subtransmission link, the zone substation power transformers and incoming switchgear are also constrained, as the subtransmission circuits were matched to the capacity and rating of the transformers and switchgear.

Johnsonville zone substation is supplied by two 33kV circuits from the Takapu Road GXP, which start as an overhead line through rural land and then change to underground cables for the last 5 kilometres into Johnsonville. Should a subtransmission fault occur at or near peak demand periods, some load can be transferred to adjacent zone substations via the 11kV distribution system. Initial high level studies indicate that the capacity of the 11kV distribution system is limited and insufficient to allow for load transfer away from Johnsonville as loads begin to grow in the short to medium term.

The Johnsonville area is experiencing higher than average growth (1.5% vs. system average of 0.4%-0.5%) as it has a large number of residential subdivisions being developed. Growth is forecast to continue given its proximity to the motorway and Wellington City, and the presence of large tracts of undeveloped land. Commercial developments requiring loads in excess of 1MVA are currently in progress.

A detailed study was conducted which considered asset capability and loadings, network constraints, security and reliability criteria and overall business impacts.

8.6.2 Network Loading Constraints

Should a sub transmission circuit fault occur, the loading on the remaining circuit will be above cyclic ratings as illustrated in Figure 8-5. The most severe constraint is imposed by the winter cable rating, although summer cable rating limits are also an issue, although to a lesser extent. Transformer ratings are breached less frequently than the cable ratings. In the event of a cable or transformer outage, it is likely to be a long duration outage, with sustained overloading as subtransmission cables and zone transformers generally require long repair windows following a forced outage.

The 11kV distribution system has the ability to accommodate the temporary transfer of about 15% of peak load (3.0MVA) to adjacent substations by reconfiguring the open points. This type of temporary transfer however will compromise reliability due to increase in feeder loading of the adjacent feeders, increased customer numbers on the feeder leading to higher than normal SAIDI and SAIFI impacts and significantly reduced post-contingency network switching capacity.

In emergency conditions a further 2.0 MVA of load is estimated to be able to be dumped by offloading hot water load. This can be problematic to restore as the restored load will be much higher than the load initially dropped (as water cools down and thermostats switch back on). Both of these situations lead to no further capacity to deal with post-contingency events elsewhere in the area.

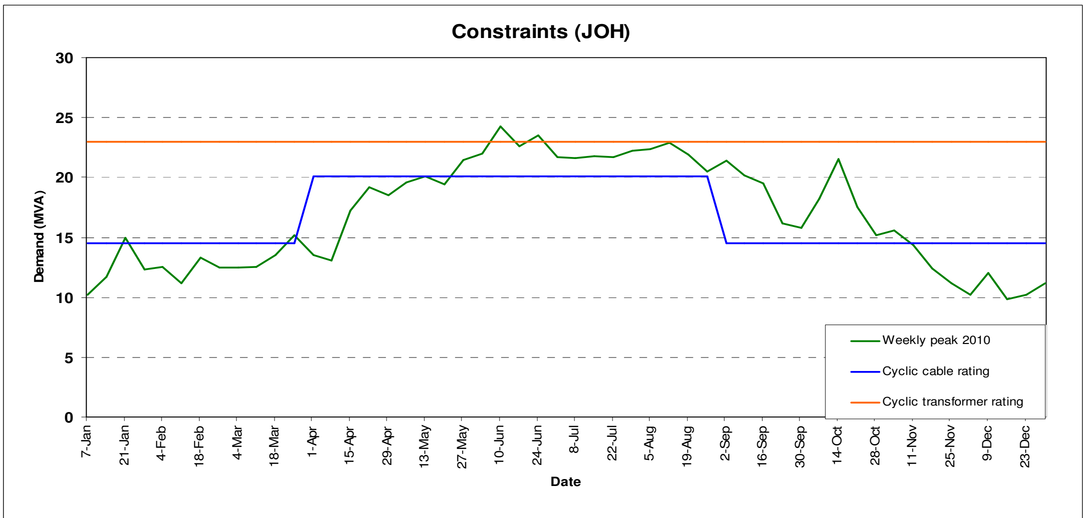

Figure 8-5 Johnsonville subtrans N-1 Equipment and Zone Tx Capacity Constraints (2010)

The constraint analysis illustrates that should a subtransmission cable be out of service at peak load times in the winter, the remaining cable will be loaded above its long term cyclic rating. The frequency and magnitude of operation above rating is high at present, and exceeds Wellington Electricity's security criteria (Figure 8-6), and will increase as load growth continues in the area. Overloads will be more frequent during the winter period than in the summer.

Type of Load	Security Criteria
Mixed commercial / industrial / residential substations	N-1 with a break for 98% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.

Figure 8-6 Wellington Electricity's Security Criteria for Subtransmission Network

The load duration curve in Figures 8-7 and 8-8 illustrates that the overloading at Johnsonville has exceeded Wellington Electricity's network security criteria.

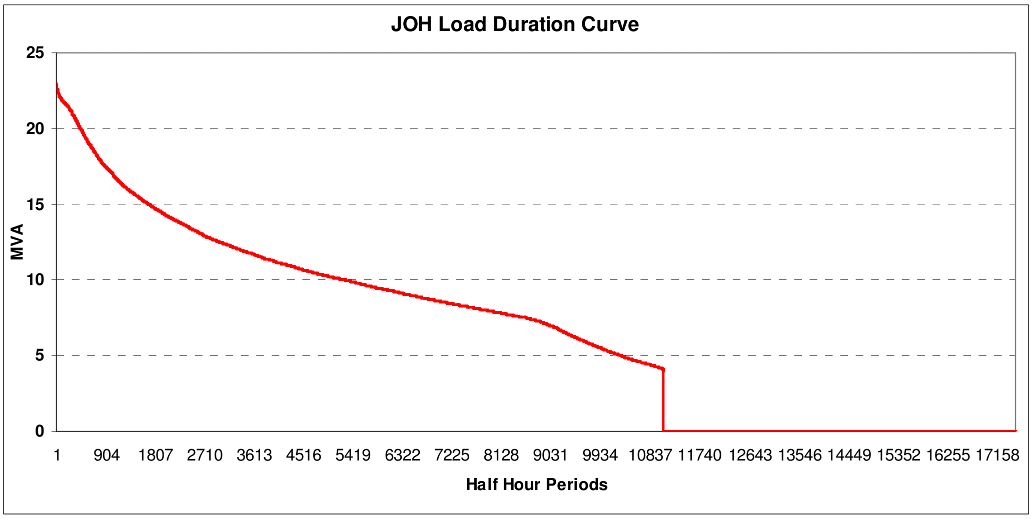

Figure 8-7 Load Duration Curve for Johnsonville Zone Substation

System Loading - Present	
Sub transmission single circuit rating	20.10 MVA
Circuit load at 98% availability	20.45 MVA
Subtransmission N-1 availability	97.5%

Figure 8-8 Wellington Electricity's Network Security Criteria Exceeded

8.6.3 Asset Capability and Loadings

There are two 11.5/23MVA 33/11kV transformers installed at Johnsonville, both were manufactured in 1969 and are in good overall condition as suggested by recent transformer and tap changer oil testing (DGA).

The 11kV switchgear comprises a board of 11 units of Reyrolle LMT with oil filled circuit breakers in acceptable condition. The switchgear fault rating is 13.1kA and the prospective fault current on the Johnsonville bus is 8.67kA thus well within switchgear ratings.

The 0.35in2 3c 33kV Al PIAS (paper insulated aluminium sheath) oil filled cables have circuit lengths of 5.05km and were installed in 1969. These cables are generally reliable and have not experienced modes of failure similar to gas cables installed on the network. The overhead section of these circuits is constructed from 'Butterfly' 19/4.64 bare AAC conductor which has a rating of 31/45 MVA summer/winter. This line is of the same age as the cables and is in good condition with an adequate rating. The circuit constraint exists in the underground cable, and also the transformer ratings.

Winter	**Circuit**	**Maximum Continuous Ratings**		
Temp=15C	1	281A (16.1MVA)		
STR = 1.2 C m/w	2	281A (16.1MVA)		
		Long Term Cyclic Ratings		
	1	351A (20.1MVA)	**367A (21.0MVA)**	Out of service
	2	351A (20.1MVA)	Out of service	367A (21.0MVA)
Summer		**Maximum Continuous Ratings**		
Temp = 23C	1	193A (11.03MVA)		
STR =2.15 C m/w	2	193A (11.03MVA)		
		Long Term Cyclic Ratings		
	1	240A (13.7MVA)	**254A (14.5MVA)**	Out of service
	2	240A (13.7MVA)	Out of service	254A (14.5MVA)

Figure 8-9 Johnsonville 33kV Subtransmission cable ratings

The risks can be summarised as follows:

1. Should a subtransmission fault occur on one circuit during peak load times, there will be a shortfall in network capacity at the Johnsonville zone substation which may not be met through switching at 11kV. This shortfall will occur if the contingency coincides with peak load, and is forecast to get worse as load grows in the area.
2. New customer connection loads cannot be connected without adding to the loadings in the area, and therefore further compromising network security.
3. The disclosed security criteria for subtransmission supply to the Johnsonville zone substation has been exceeded and will continue to deteriorate as load grows.
4. Further transfer of load to other feeders without further network reinforcement will increase reliability issues, in particular with regard to customer numbers on each feeder impacting SAIDI and SAIFI metrics, as well as potentially overloading the 11kV network.

8.6.4 Reinforcement Risk Assessment Process

Non-network options including distributed generation and demand side management were considered however after evaluation were deemed not to be effective to address the risks identified at Johnsonville zone substation.

Three Network options were identified:

Option 1 - the installation of an additional 33kV sub transmission circuit from Takapu Rd GXP to Johnsonville zone substation to operate in parallel with the existing circuits, plus reinforcement of the 11kV switchboard and circuit breaker ratings by retrofitting new circuit breakers. This was discounted based on the current acceptable condition of network assets and cost.

Option 2 – Transfer load to a new zone substation. This option would involve building a new zone substation of a similar configuration to Johnsonville, located within the Grenada Village area, to move load away from existing zone substations. This new zone substation would provide capacity for the high levels of growth occurring north of Johnsonville.

The 33kV subtransmission supply for this new zone substation would be from the existing Ngauranga 33kV overhead line which is presently leased from Transpower. (Resource Management Consenting would be required for the 33kV route).

The benefits of this option are that it provides a long term solution to create more capacity, and improves network security through adding another in-feed to the high growth Johnsonville area. The disadvantages of this are the relatively high costs and long timelines associated with developing a new substation.

This option was not recommended as a short term solution for Johnsonville, as the development timeframe will be longer than ideal to address the immediate risks. However it will need to be considered in the medium term if load growth continues at the forecasted rates.

Option 3 – Transfer load to an existing adjacent zone substation. Ngauranga zone substation adjacent to Johnsonville has lower utilisation than Johnsonville and experienced lower growth in recent years and lower forecast load growth. Utilising this existing network capacity is a means of deferring major investment in new subtransmission capacity in the short to medium term.

This option involves reconfiguring the Johnsonville distribution feeders (JOH05 and JOH11) so that a portion of the 11kV load is supplied from a new 2.2km long Ngauranga feeder.

This option provides a medium term solution but as loads in the area continue to grow the N-1 capacity of the Johnsonville subtransmission system will once again be reached. A new zone substation (as per option 2) is forecast to be required north east of the existing Johnsonville substation in five years time. This time frame may be extended however if growth rates slow.

Option 3 was preferred and considered the most appropriate as it provides a short to medium term solution within a short construction time frame while also addressing the immediate network risk.

Figure 8-10 shows the risk likelihood for the preferred option 3.

	Inherent Risk (existing system)	Residual Risk (option 3)
Likelihood	Should either a subtransmission or distribution fault occur during peak load times, there will be a shortfall in network capacity at the Johnsonville zone substation which could not be met through switching or load control. This shortfall will only occur if the contingency coincides with peak load. **Classification** - Likely	The probability of a shortfall following the load transfer works is negligible. **Classification** - Rare

Figure 8-10 Risk Likelihood for Preferred Option 3

	Inherent Risk (existing system)	Residual Risk (option 3)
Financial consequences	Loss of revenue and potential claims for compensation from affected consumers **Classification** - < $100k	No consequences. **Classification** – No impact
Health & Safety consequences	No H+S consequences **Classification** – No impact	No consequences **Classification** – No impact
Environment consequences	No environmental consequences **Classification** – No impact	No consequences **Classification** – No impact
Reputation consequences	Blackouts will attract some negative media coverage. **Classification** - Moderate	No consequences **Classification** – No impact
Compliance consequences	No compliance issues **Classification** – No impact	No consequences **Classification** – No impact
Customer Service / Reliability consequences	Blackouts will affect consumers and impact on network reliability metrics. **Classification** – Moderate	No consequences **Classification** – No impact
Employee satisfaction consequences	No consequences **Classification** – No impact	No consequences **Classification** – No impact

Figure 8-11 Risk Consequence for Preferred Option

Risk Analysis	Inherent	Residual
Likelihood	**25**	**3**
	Likely	Rare
Consequence	**16**	**0**
Financial	<$100k	No impact
Health & Safety	No Impact	No Impact
Environment	No Impact	No Impact
Reputation	Moderate	No Impact
Compliance	No Impact	No Impact
Customer Service / Reliability	Moderate	No Impact
Employee Satisfaction	No Impact	No Impact
Level of Risk (Risk Rating)	**392**	**0**
	High	Not Assessed

Figure 8-12 Risk Analysis Table for Option 3

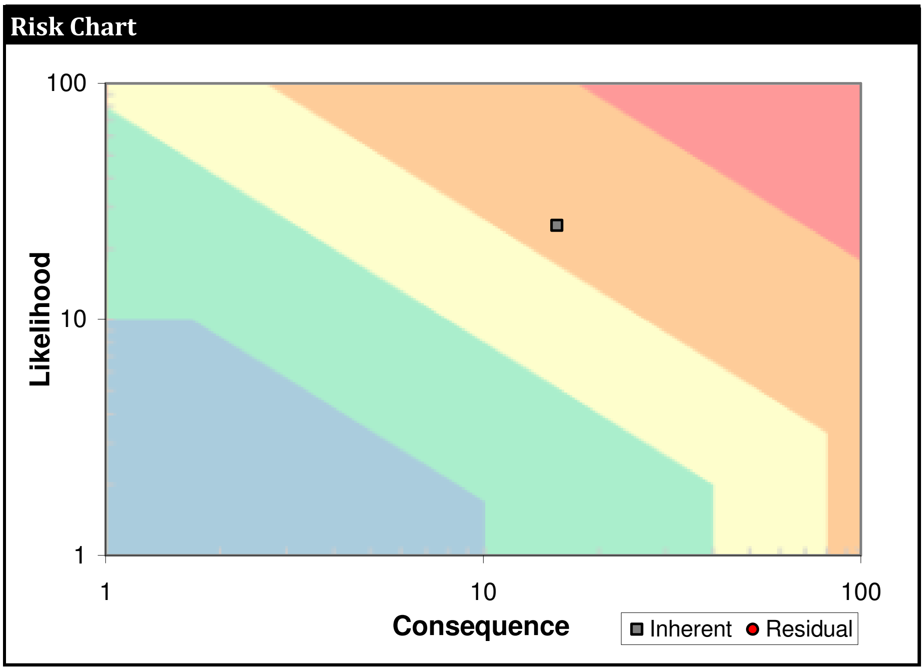

Figure 8-13 Risk Analysis Chart for Option 3

Note that the residual risk is zero and therefore does not show on the chart in Figure 8-13.

The outcome and recommendation of the risk analysis was collated into a business case and presented to the Capital Investment Committee in June 2011. The business case was approved and the cable reinforcement project was completed in January 2012.

8.7 Risk Based Approach to Asset Management

The AMP assists the decision making process for phasing out an asset through a planned replacement programme, or continuing in service supported with additional inspection and preventative maintenance activity. Through the revisions made to the Field Service Agreement in 2011, an increased level of condition and risk information is being provided to Wellington Electricity through the inspection and condition assessment programme. This information is entered into Wellington Electricity systems which in turn feed into the network planning processes. This allows greater analysis of the risks on specific assets, or groups of assets which enables Wellington Electricity to optimise its expenditure to manage risk and performance of the network.

In addition to this, the prioritisation of capital works (refer to Sections 5 and 6) is based on an assessment of the risk that each potential project carries.

8.8 Risk and Hazard Identification

All staff members are encouraged to identify risks and hazards and raise these to the appropriate supervisor or manager. Risks are identified as part of the incident management process. New risks are added to the incident management register for evaluation, recommendation, action and close out. All risks that follow the incident management process will undergo root cause analysis to identify the underlying problem and appropriate mitigation action.

Business risk is managed through regular risk profiling workshops with the objective to identify and assess the risks which may impact on the business achieving its strategic objectives. Some risks which cannot be eliminated are assigned controls to minimise or mitigate the impact to the business should the risk occur.

8.9 Specific Network Risks

There are a number of areas within a network business where certain types of assets can exhibit performance which is sub-optimal, or they may deteriorate to an in-service failure point ahead of their expected life. Provided these issues are understood and monitored, the risk of in-service failure can be managed to a point where it is tolerable and controls can be put in place to reduce their impact should they occur.

The following table shows the top ten risks identified for the network.

Rank	Event	Inherent Rating	Residual Rating
1	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources).	Extreme	High
2	Injury or damage caused or loss suffered to third parties.	Extreme	High
3	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets.	High	High
4	Sub-optimal performance or failure of network assets.	Extreme	Medium
5	A loss of connection supply from transmission assets.	Extreme	Medium
6	A health and safety incident that affects one or more employees, contractors or visitors while performing work or visiting the Business' properties, assets or worksites.	Extreme	Medium
7	Release or spread of hazardous materials, Electromagnetic Fields (EMF) or noise to land, ecosystems or atmosphere.	Extreme	Medium
8	Mis-management of a crisis and emergency affecting the Network.	Extreme	Medium
9	Failure of a retailer, customer, supplier or contractor to perform their contracted obligations, including financial obligations.	Extreme	Medium
10	Non compliance with relevant laws, regulations and reporting requirements.	Extreme	Medium

Figure 8-14 Summary of Top Ten Network Risks

The Risk Profiling process identified no (current) Extreme residual risks and three High residual risks. The average residual risk across the business remains at Low. This is the same residual result as assessed in 2011 indicating a stable risk environment for Wellington Electricity's business at a network level.

Each risk has a Risk Treatment Plan to reduce the residual risk as far as practicable. These Risk Treatment Plans will be managed in conjunction with the Risk Owners and monitored to ensure that Wellington Electricity is taking proactive steps to mitigate risk. The Plans include a simple cost benefit analysis to assess the practicability of the improvement options and assist decision making. The Plans also document the acceptance of the risk at this level. Reporting on the status of high level business risks is made to the SMT and the Board via the Audit and Risk Committee.

8.10 Network Resilience

The Wellington region is a seismically active area with known fault lines. There is a risk from liquefaction in some areas and risk from tsunami in low lying coastal areas. Due to the Christchurch earthquake events in September 2010 and February 2011 there has been increasing social and business awareness for not only the need for a safe and reliable electricity supply but for a resilient infrastructure that can restore power as safely and quickly as practically possible following a major event.

Wellington Electricity has developed a suite of Emergency Response Plans to recover from various network incidents and events. These include Business Continuity, Crisis Management and Major Event Management Plans as described in Section 8.12. In preparing for the Lifelines report (refer to 8.10.2), improvements to these plans were identified.

8.10.1 Reinforcement and Resilience Investment

Resilience investment covers both building seismic reinforcement and network resilience upgrades to improve performance and response to a major earthquake. This investment is not currently included in Wellington Electricity's capital expenditure forecasts and therefore is not included in the current lines charges.

The assessment of building strength and the subsequent reinforcement is a legislative change imposed by local government resulting in an increase in costs for Wellington Electricity. These should be treated as a pass-through cost to consumers in the same manner as rates and other local body charges. The obvious benefits and importance of further network resilience investments are best recovered through the Default Price Path as this is considered a highly effective form of self insurance benefitting consumers (i.e. a small cost incurred by consumers before the event rather than a significantly larger cost following the event with long delays in service restoration). Wellington Electricity believes the costs and time incurred to prepare a Customised Price Path application for this specific issue is unnecessary, and the additional costs to consumers in preparing this application are not justified.

Wellington Electricity's approach to earthquake prone buildings is not just about minimising loss of life during an earthquake event but also supporting local communities and economy to return to normal as soon as possible after an earthquake event. The recently released report "Infrastructure 2012: National State of Infrastructure Report: A Year on from the National Infrastructure Plan" considers the level of resilience of New Zealand's infrastructure and whether the current regulatory settings facilitate the level of investment needed to meet long-term infrastructure needs. Wellington Electricity welcomes this discussion and is engaging with the Government and Local Authorities to identify suitable solutions.

There have been a number of lessons learned from the Canterbury earthquakes around the benefits of resilience investment. Orion identified that an upfront investment of $6 million on strengthening buildings in the 1990s resulted in savings around $60 million in the reconstruction of their network and improved response times following the earthquakes. Based on this ratio of 10%, if applied to Wellington Electricity network, an investment of around $30 million now would protect around $300 million of assets from earthquake damage. This expenditure would provide security of supply into Wellington, improve restoration times for vulnerable cable assets and enable substation buildings to remain operational.

Wellington Electricity estimates that the following level of investment would be required to address Seismic Reinforcement projects.

Investment Area	2013-2015	2015-2023
Substation Seismic Improvements and Assessment	Assessment Phase	$30 million

Figure 8-15 Overview and Cost Estimate for Seismic Assessment and Improvements

8.10.2 Wellington Lifelines Group (WeLG)

Wellington Electricity is an active participant in the Wellington Lifelines Group (WeLG). WeLG brings together various utility and transport operators in the Wellington region to identify and prepare contingency plans for the region following a major disaster.

During 2012 Wellington Electricity participated in a group led by the Civil Defence Emergency Management (CDEM) to compile a report outlining the resilience and response to a simulated earthquake event in Wellington. This report highlighted the vulnerability of the area to a major event following a magnitude 7.5 earthquake on the Wellington faultline and identified that a number of basic services would be unavailable for up to 95 days in some areas and longer in some other areas. Road transport would be affected preventing the movement of personnel, plant and materials to repair failed assets. In addition, corridors into the Wellington Region would be blocked limiting the ability to bring materials into the area, thus increasing dependence upon locally held strategic spares.

The report concluded that although there is no control over earthquake likelihood, an increase in resilience could help improve the response times and reduce the consequences. Further work will be required to understand the interdependencies between the various utilities, and what each parties needs are and Wellington Electricity will continue to engage with WeLG.

Wellington Electricity has identified, in addition to building seismic issues above, the following areas where resilience can be improved on the network:

- Subtransmission Cables
- Storing strategic spares in various locations around the Wellington Region

Estimates of these costs are being developed and will be included in future plans.

8.10.3 Identification and Management of High Impact – Low Probability (HILP) Events

Wellington Electricity identifies High Impact-Low Probability (HILP) events through some of the following methods:

- Transmission risk reviews – participation in the Connection Asset Risk Review (CARR) project undertaken by Transpower. Transpower are also presently undertaking a HILP event study for the Wellington region at Wellington Electricity's request which will identify risks on the transmission circuits and substations.

- Distribution risk reviews – as part of the network planning process, HILP events are identified such as major loss of subtransmission risks (e.g. Wainuiomata double circuit 33kV outage, Trentham loss of zone substation due to a protection comms failure coincident with a 33kV fault), and substation risks (e.g. catastrophic loss of a CBD zone substation).

- Environmental risk reviews – understanding and identification of the risk posed by natural disasters such as earthquake and tsunami, and studies undertaken on our behalf by GNS and other external providers.

8.10.3.1 Strategies used to manage HILP events

Wellington Electricity applies the following strategies to manage HILP events drawing from experience of others (such as learnings from Orion following the Canterbury earthquakes)

- Identification – to understand the type and impact of HILP events that the network may experience, through individual studies. .
- Elimination – to minimise the consequence of the HILP event through investment in resilience and network assets.
- Mitigation – investigate options for reduction of the impact of the HILP event, such as diversifying assets or supply paths and improving resilience of existing network.
- Response – develop plans to respond to HILP events in terms of business process. This includes practising response under these plans and improving capability and staff awareness. These plans are detailed in section 8.12.
- Recovery – understand requirements for contingency plans to invoke a staged and controlled restoration of network assets and supply capability.

8.10.4 Seismic Reinforcing of Equipment and Buildings

Wellington Electricity has continued to be proactive in surveying and identifying any potential seismic issues with regards to the assets in network buildings. Major equipment within zone substations such as transformers and switchgear, service transformers and battery stands have been seismically restrained. Also any heavy loose equipment has been removed from substations and relocated to a centralised store. Ongoing maintenance inspections and notified defects from site visits will continue to identify any assets requiring further seismic support.

Figure 8-16 Zone Substation Power Transformer Seismic Restraint Footing

Substation building installations generally comply with the relevant building code applicable at time of construction. Local councils conduct assessments of selected buildings within their region that have been built or strengthened to pre-1976 structural design codes to ensure compliance with their Earthquake Prone Buildings Policies. This was driven by changes under the Building Act 2004 which covers all building types and requires older buildings to have the performance capacity of at least one third (33%) of that of a new building. A building is evaluated using the Initial Evaluation Process (IEP) as set out in the New Zealand Society for Earthquake Engineering Recommendations for the assessment and Improvement of the Structural Performance of Buildings in an Earthquake.

Wellington Electricity has received 34 IEPs from Councils to date, and also assessed 11 buildings itself in relation to capital works improvements. Of these buildings, 11 have been identified as potentially earthquake prone. Consequently, Wellington Electricity engaged independent local structural consultants to review the buildings' resilience. The independent structural consultants have assessed and confirmed that 7 buildings are earthquake prone buildings meeting less than 34% of the New Building Standard (NBS), the remaining 4 buildings are the process of being assessed at the time of writing this plan. In 2011, one building (70 Adelaide Rd) was reinforced to 67% of NBS, and there are designs in progress for the strengthening of Chaytor Street, 9 Duncan Terrace and the Newtown substation, however the funding mechanism for recovery of investment remains unclear. If this work proceeds, this will bring the substations above 34% NBS and they will no longer be classified as earthquake prone. It is not always efficient to bring the building up to 67% NBS, however the strengthening work undertaken is to achieve effective reinforcement to minimise the risk to public, personnel and to the electrical plant within the building.

Wellington Electricity embarked on a programme of assessment of substation buildings with the aim to assess between 50 to 100 buildings per annum over the following three to four years to understand the risk associated with the population of building type substations. At the completion of this work, a more accurate assessment of the required level of capital investment will be known. This is also discussed in section 6.4 (Maintenance and Renewal Programmes).

In 2012, Wellington Electricity engaged a structural consultant, who has previously designed seismic reinforcing for both Orion and Transpower substation buildings, to assist in the development of a seismic reinforcing guideline standard for Wellington Electricity owned substation buildings. This guideline will outline the basic parameters of effective and practical seismic strengthening construction based on the principles employed for buildings that successfully withstood the impact of the Christchurch earthquakes in September 2010 and February 2011.

Accordingly, Wellington Electricity has reviewed its policy on the categorisation, assessment and management of substation building seismic strength and requirements for reinforcing. The revised policy provides the business guidance on the risk and importance of each Wellington Electricity owned substation building and establishes the priority that would be required should Wellington Electricity commence a programme of reinforcement works.

Wellington Electricity's other design and construction standards and specifications comply with current seismic design codes. Typical issues in respect of the new codes are tie down of distribution transformers (older transformers may have their wheels chocked and have hold-down brackets fabricated) and older brick buildings that do not meet current seismic codes. Newer berm type substations are bolted to concrete plinths which have been placed on a formed flat ground platform. No specific restraint has been integrated into these installations.

The known sites that require seismic upgrades (as a result of having strength < 33% of NBS) during the planning period are:

Substation	Year Identified	Year Scheduled	Estimated Cost
Newtown	2011	To be determined	$800,000
Chaytor St	2011	To be determined	$100,000
9 Duncan Tce	2011	To be determined	$100,000
Ghuznee St	2012	To be determined	To be determined
176 Wakefield St	2012	To be determined	To be determined
Herd St	2012	To be determined	To be determined

Figure 8-17 Known Sites that Require Seismic Upgrade

In addition to this list, a seventh site (Cornwell St) has been found to be earthquake prone but, as described in Section 6, it is possible to decommission this substation for possible demolition as opposed to strengthening it.

Managing the seismic building risk is a huge task and the improvements to these buildings will divert capital which would otherwise have been used for replacement of electrical distribution assets. Under the present regulatory Default Price Path regime there is no mechanism to obtain extra funding for disaster resilience projects such as this, other than applying for a full Customised Price Path application which is costly and uncertain.

8.10.5 33kV Overhead Emergency Corridors

Underground sub-transmission cables utilising gas and oil filled technologies can be vulnerable to seismic events. Repair to extensively damaged gas and oil filled cables could take a number of months, which is unacceptable. Wellington Electricity has engaged with Wellington City Council (WCC) to specifically address this issue in the event of an earthquake and to develop the protocols regarding the emergency installation of overhead 33kV lines should sub-transmission cables become unavailable for an extended period following a major event.

Wellington Electricity has engaged a line design consultant to carry out 33kV temporary overhead route planning and line design to supply CBD zone substations from Transpower GXPs in case of damage to underground sub-transmission cables during an earthquake or any other catastrophic event. The selection of the proposed routes shall consider all risks within their immediate vicinity such as earthquake prone buildings, vegetation, topography, ground conditions and ease of access for construction.

The temporary 33kV overhead routes to Hataitai, Palm Grove and University zone substations have been designed and surveyed by Wellington Electricity's line design consultant. Each route design provides the pole location and line route along with pole structure design drawings. The planning and design of 33kV overhead routes for the rest of the CBD zone substations is underway and will be complete by the end of 2013. The temporary 33kV overhead line structures are based upon a standard design used across the network, which would involve common materials and use normal construction practices when the time comes to build these temporary structures.

The key outcome from the planning and design will be a set of defined 33kV overhead line emergency corridors and appropriate support structures that will be socialised with Wellington City Council (WCC) for consideration of implementing the corridors and these structures within the District Plan emergency provisions. Engagement with the remaining Wellington area councils will commence following the Wellington CBD study.

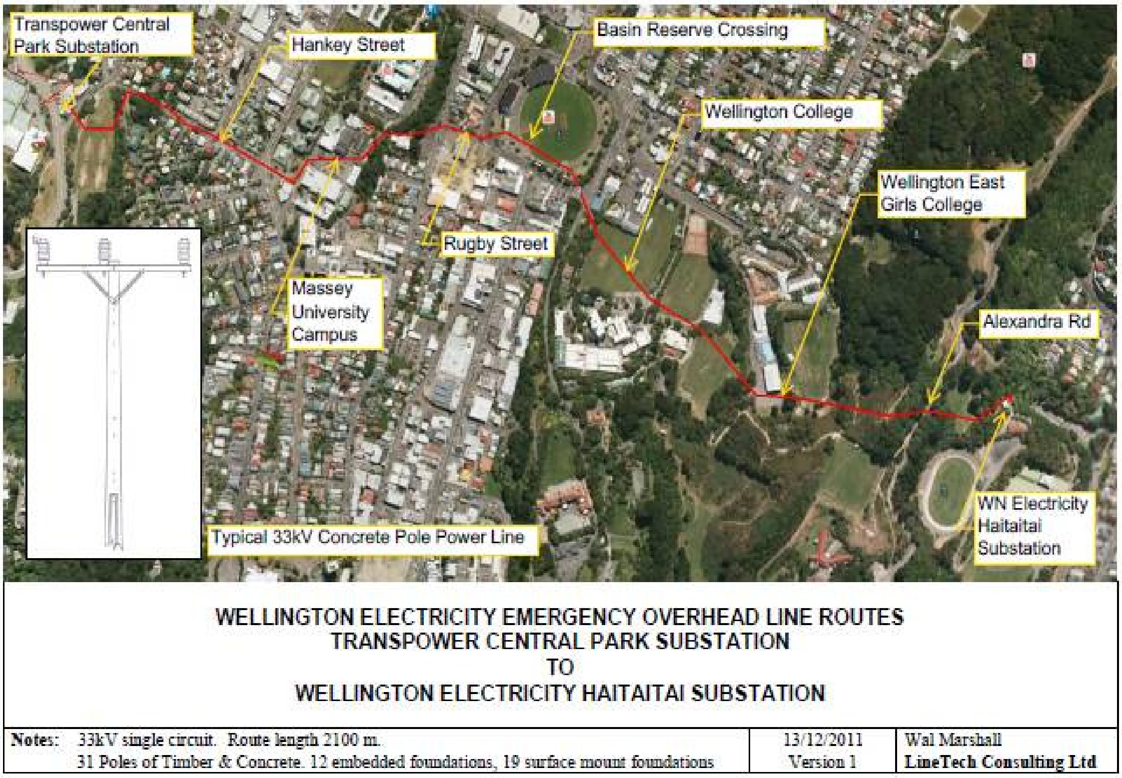

Figure 8-19 33kV Emergency Overhead Line Corridors (Example only)

The prototype of the surface foundation structure shown in figure 8-20 has been fabricated and a testing regime is being developed to prove the concept in 2013. If testing is successful a decision will be made as to whether a quantity of these will be held at various locations around the Wellington area, along with the required materials such as poles, pole hardware and conductors. Purchasing and holding these materials would represent a large investment which would need to be recovered through an appropriate price recovery mechanism as discussed earlier in section 8.10.1.

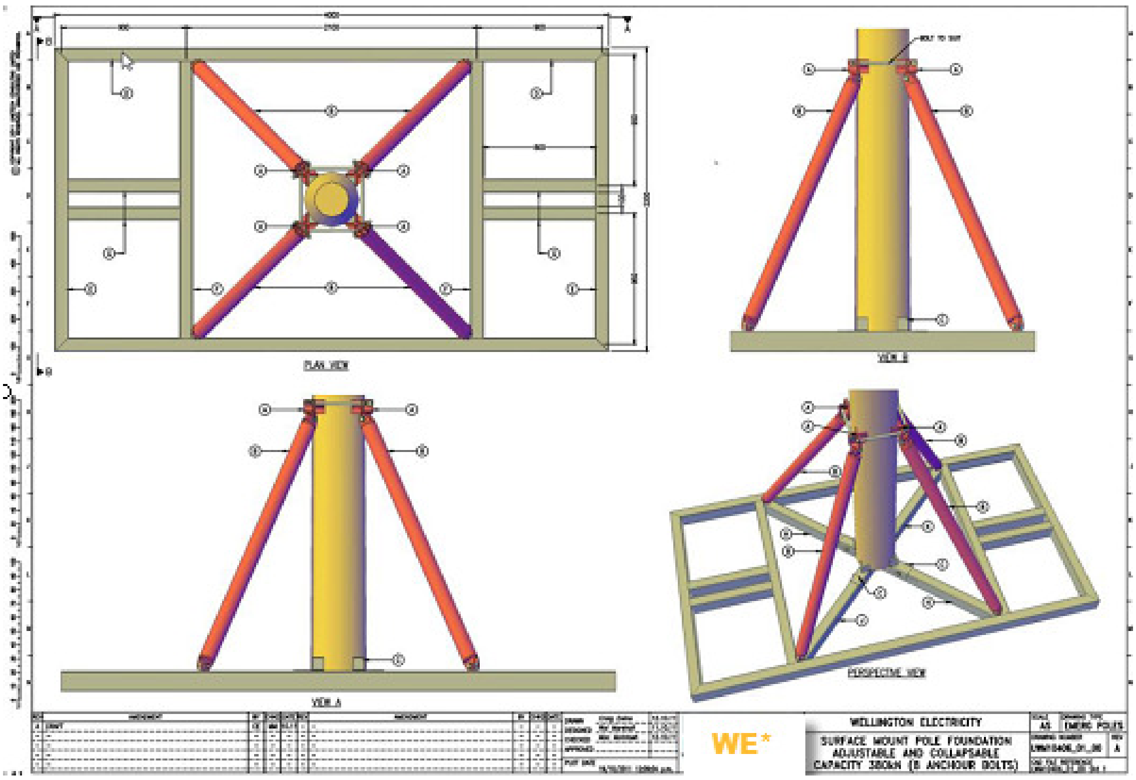

Figure 8-20 33kV Pole Structure Supports (Example only)

8.11 Insurance

8.11.1 Insurance Cover

Wellington Electricity renews its insurances in two tranches. The Industrial Special Risks (ISR) Insurance which includes Material Damage and Business Interruption cover is renewed annually as at 30 June.

The Company's general products and liability insurance is renewed annually as at 30 September. These insurances include: general, products, pollution, electro-magnetic radiation, financial loss (failure to supply), and professional indemnity.

The renewal process for all insurances commences four to six months prior to the expiry of existing policies in conjunction with the appointed broker and the expertise of the wider CKI Group. Insurances are generally placed at least 10 business days prior to the policy expiry date.

The global market for insurance is challenging, given the number of recent major disaster events that have resulted in significant damage and insured losses including, but not limited to, the events such as floods in Thailand and Queensland, tsunami in Japan, earthquakes in Christchurch and Hurricane Sandy in the USA.

Changes within the global insurance industry resulting from these events are emerging with insurers adopting a strict technical attitude towards rating and retention levels in an attempt to recover losses. The New Zealand market has suffered substantial losses in Christchurch leading to most insurers having reduced capacity and substantially increased reinsurance costs. Some insurers have since exited the market. The Reserve Bank has also tightened capital requirements for insurance companies operating in New Zealand.

In 2012 Wellington Electricity commissioned an updated GNS Science report to assist in quantifying its insurance risk and requirements and to help mitigate insurance premium increases. GNS Science estimated losses to insured assets from potential earthquake and tsunami events. This report indicated a low probability of a significant seismic event from known earthquake faults and in any event estimated losses to insured assets were within existing insurance limits.

Wellington Electricity will continue to work with the wider CKI Group to obtain lower priced insurance premiums than could be achieved on a standalone basis in New Zealand. Due to the earthquake exposure and following the Christchurch earthquakes, insurance capacity for Wellington based risks has become more difficult to source. Accordingly Wellington Electricity has engaged other markets, notably the London market, to ensure appropriate insurance cover is maintained.

8.11.2 Risk and Recovery of Increased Insurance Premiums

Wellington Electricity only insures 20% of the estimated replacement cost of strategic network assets such as substation buildings and related equipment. The level of insurance cover purchased is based on estimates by GNS to determine our Maximum Foreseeable Loss. There are significant costs to increasing insurance cover beyond this. Whilst the Commerce Commission has recognised that insurance premiums have significantly increased, there is currently no mechanism through the default and customised price path regimes for self insurance (potential losses on uninsured assets in a major event) to be recovered. This risk based approach enables customers to pay lower prices now, with costs incurred to restore power following a major event recovered at that time. Following the Christchurch earthquakes, Wellington Electricity has been engaging with the Commission to seek clarity about how the risk from uninsured assets is best managed. This could be through either an additional risk premium on the regulated return on investment or straight cost pass through to consumers, i.e. through increased lines charges or through Government providing funding post a major event such as an earthquake.

The significant increase in insurance premiums experienced in 2011and 2012 and forecast for the next few years has led to consultation with the Commission around recovery of the increased costs being incurred to reduce the impact on customers from unplanned events. The Commission has allowed distribution businesses to pass through the increase in insurance premium costs to customers. This is important for Wellington Electricity to be able to recover resilience investments.

8.12 Emergency Response Plans

As part of the Business Continuity Framework Policy, Wellington Electricity has a number of Emergency Response Plans (ERPs) to cover emergency and high business impact situations. The ERPs require annual simulation exercises to test the plans and procedures which provide feedback for any areas of improvement. All ERPs are periodically reviewed and revised to best meet the emergency management and response requirements of Wellington Electricity.

The ERPs are described in further detail below. The following chart shows how the various plans link together through each escalation level, as well as the key personnel involved with each of those stages.

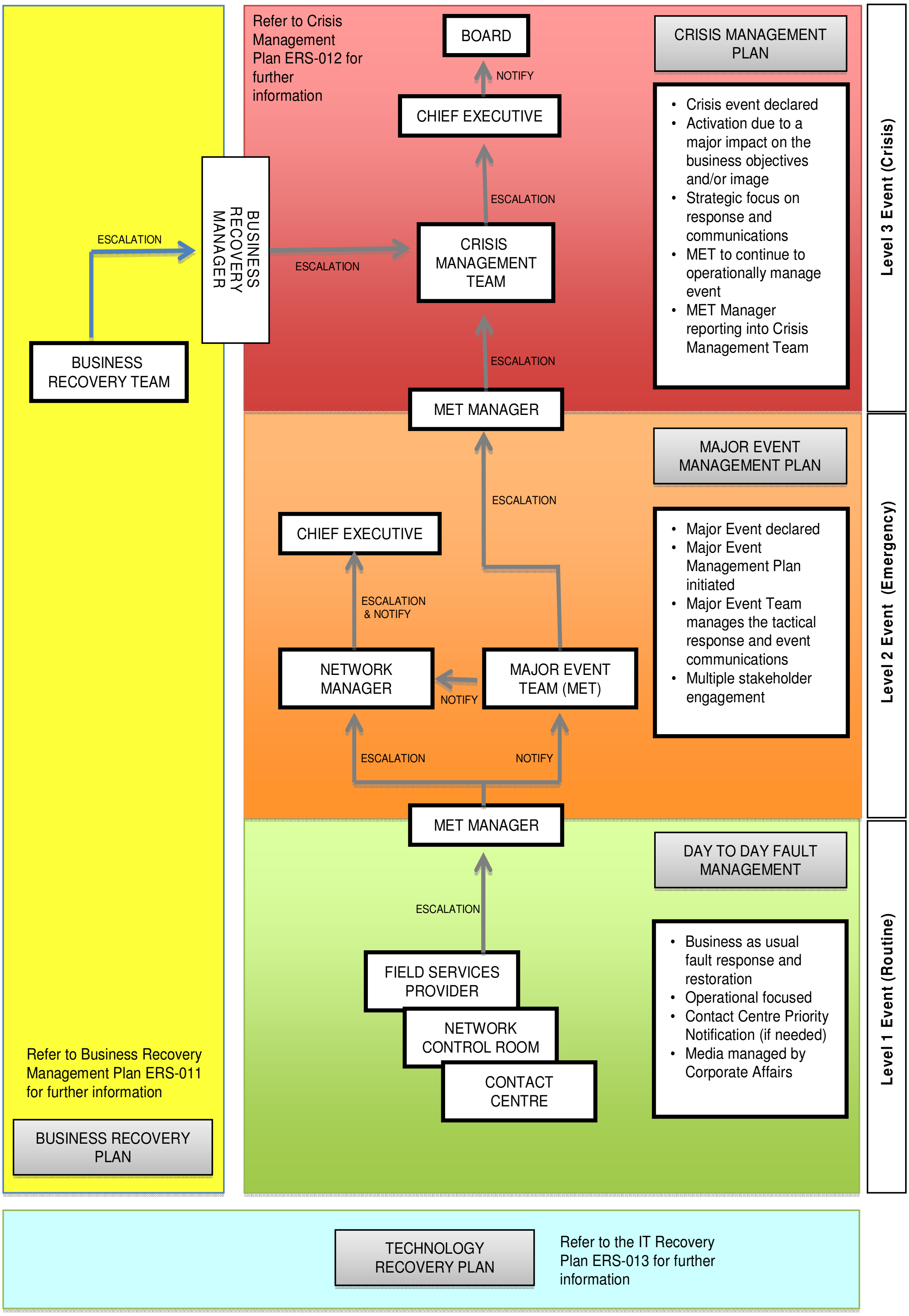

Figure 8-21 Emergency Response Escalation Framework

8.12.1 Crisis Management Plan

The purpose of the Crisis Management Plan (CMP) is to ensure that Wellington Electricity is prepared for, and responds quickly to, any crisis that occurs or may occur on its network. The CMP defines the structure of the Crisis Management Team and the roles and responsibilities of staff during a crisis. This plan was tested during 2012 in conjunction with the Major Event Management Plan simulation.

The CMP contains detailed contact lists of all key stakeholders who may contribute to or be affected by the crisis.

8.12.2 Major Event Management Plan

The purpose of the Major Event Management Plan (MEMP) is to ensure that Wellington Electricity is prepared for, and responds quickly to, any major event that occurs or may occur on its network. The MEMP defines a major event and describes the actions required and the roles and responsibilities of staff during a major event.

A particular focus of the MEMP is how the internal and external communications are managed. The plan contains detailed contact lists of all key stakeholders who may contribute to or be affected by the major event.

The MEMP can escalate to a crisis and then be managed in accordance with the CMP.

Major event simulation exercises were carried out during 2011 and 2012 to stress test the MEMP process and the major event team roles and responsibilities.

8.12.3 Business Recovery Management Plan

The purpose of the Business Recovery Management Plan (BRMP) is to ensure that Wellington Electricity is prepared for, and responds quickly to, any event that interrupts the occupancy of its corporate offices in Petone and clearly states how such a business interruption would be recovered and escalated to a crisis if required. This includes the mobilisation of the Business Recovery Event Centre at the Wellington Electricity Disaster recovery site at Haywards.

A desktop simulation exercise was completed in 2011 and again in 2012 which assisted in identification of the necessary business recovery infrastructure provisions and key business recovery timeframes.

8.12.4 Information Technology Recovery Plan

The purpose of this plan is to ensure that Wellington Electricity IT systems are able to be restored quickly following a major business interruption affecting these systems. The level of recovery has been determined based upon the business requirements.

This plan was tested in 2012 and a number of improvements were identified and actioned.

8.12.5 Major Event Field Response Plan

The purpose of the Major Event Field Response Plan is to ensure that Wellington Electricity's Field Contractors are prepared for, and can respond appropriately to, a storm or potential storm that may impact on the network. The Major Event Field Response Plan describes actions required and responsibilities of

Wellington Electricity and Field Contractor Coordination during a storm emergency and focuses on systems and communications (internal and external) to restore supply to customers. The Plan can escalate to the MEMP if required.

8.12.6 Emergency Evacuation Plan

The purpose of the Emergency Evacuation Plan is to ensure that the NCR is prepared for, and responds quickly to, any incident that requires the short or long term evacuation of the NCR and re-establishment at the disaster recovery site.

8.12.7 Civil Defence Emergency Management (CDEM) Plan

As an electricity distribution business providing essential services, Wellington Electricity belongs to the Lifeline Utilities group. There is an emphasis in the Civil Defence Emergency Management (CDEM) Act 2002 on ensuring that lifeline utilities provide continuity of operation, particularly where their service supports essential CDEM activity.

Wellington Electricity has prepared the CDEM Plan to comply with the relevant provisions of the CDEM Act. It provides information for the initiation of measures for saving life, relieving distress and restoring electricity connections.

This CDEM Plan follows the four 'Rs' approach to dealing with hazards that could give rise to a civil emergency:

- Reduction - identifying risks and developing plans to reduce these risks
- Readiness - developing emergency operational contingency plans
- Response - actions taken immediately before, during or after an emergency
- Recovery - rehabilitating and restoring to pre-disaster conditions.

8.12.8 Pandemic Preparedness Plan

The purpose of the Pandemic Preparedness Plan is to manage the impact of a pandemic related event by:

- Protecting employees as far as possible from spread of disease
- Create a safe working environment
- Maintain essential business functions with reduced staffing levels if containment is not possible.

The Pandemic Preparedness Plan is reviewed annually by the Wellington Electricity QSE manager.

8.12.9 Other Emergency Response Plans

Wellington Electricity has other emergency response plans including:

- Priority Notification Procedures to key staff and contractors
- Total Loss of a Zone Substation Plan
- Loss of Transpower Grid Exit Point Plan (Transpower Plan)
- Emergency Load Shedding Plan
- Participant Outage Plan (as required under the Electricity Industry Participation Code 2010)
- Call Centre Continuance Plan

In addition, contingency plans are prepared as necessary detailing special arrangements for major or key customers.

9 Quality, Safety and Environmental

Wellington Electricity is committed to providing excellence in Quality, Safety and Environmental (QS&E) requirements through the following principles, that:

- All employees and contractors undertake their work in a safe environment
- Members of the public are not harmed by the operation, maintenance and improvement of Wellington Electricity's assets
- Controls are effective for minimising impacts to the environment
- Processes are in place to ensure high quality outcomes are consistently achieved

To support these principles, Wellington Electricity has developed a comprehensive set of health and safety, environmental and quality policies and procedures and prioritises safety as a core business value.

Safety is a priority business value. Wellington Electricity employees and contractors are required to both personally manage their own and other people's safety by adhering to safe work practices, making appropriate use of plant and equipment (including protective clothing and equipment), promptly managing controls for assessed hazards and reporting of incidents, near misses and accidents.

Wellington Electricity employees and contractors take all reasonable steps to ensure that business activities provide an outcome which minimises environmental impacts and promotes a sustainable environment for future generations.

Wellington Electricity employees and contractors take all reasonable steps to ensure the delivery of goods, products and services are to an acceptable standard and meet the quality expectations of the business. Likewise, all employees and contractors identify and report any defects or non conformances to enable improvement in the systems or performance to maintain quality outcomes.

9.1 Community and Public Safety

9.1.1 Public Safety Management System (PSMS)

Wellington Electricity has developed a Public Safety Management System (PSMS) framework policy document which outlines the policies, procedures and guidelines relevant to the safe design and management of the assets. The PSMS includes assets that are installed in the public areas and management of these assets to ensure they do not pose a risk to public safety. The PSMS meets the compliance requirement for electricity distributors to implement and maintain a safety management system for public safety set out in Regulation 47 and 48 of the Electricity Safety Regulations (ESR) 2010.

The PSMS also meets the requirements of New Zealand Standard Electrical and Gas Industries – Safety Management System (NZS 7901:2008). In 2012 the certification body Telarc assessed Wellington Electricity against the requirements of NZS7901. Some minor updates were recommended by the audit report and these were addressed accordingly. A revisit by Telarc in January 2013 confirmed that Wellington Electricity is compliant with annual certification requirements.

Wellington Electricity continues to invest significant resources to raise awareness in the community of the potential risk of living and working near electricity assets.

9.1.3 School Safety Programme

Wellington Electricity developed an education programme for schools which teaches children about electrical safety. The Stay Safe programme is aimed at primary school aged children and delivered in schools around the Wellington Region by Wellington Electricity. The programme involves showing a DVD, electrical safety discussion aided by visual props and the presentation of the "stay safe around electricity" workbook to each child. The workbook invites children to visit the *Electricity Safety World* website.

To date Wellington Electricity has visited 44 schools and presented to over 4000 young primary school students.

9.1.4 Electricity Safety World Website

Wellington Electricity provides safety information and advice on its website www.welectricity.co.nz. The purpose of the website is to help the community stay safe around electricity and provides information on: electrical shocks, electrical fires, electromagnetic fields, appliance safety, power line safety and fault reporting details.

The website also links to other safety sites and government safety agencies. Of note is a link to the Electricity Safety World Site which contains interactive safety games and information targeted at young children and parents regarding not only network safety, but also electrical safety around the home.

9.1.5 Media Advertising

Wellington Electricity understands the importance of raising public awareness about the dangers of living and working around our network assets. During 2011 Wellington Electricity undertook a radio safety campaign which covered issues such as trees in proximity to overhead lines, cable identification and mark out, safety disconnects and advice on protecting sensitive appliances with surge protectors. During 2012 a new radio safety campaign was launched which refreshed the message of safety for similar themes.

9.1.6 Safety Seminars and Mail Outs

In order to prevent third party contact with the Wellington Electricity Network, the Quality Safety and Environmental Manager periodically delivers safety seminars to civil contracting companies (third party contractors working around Wellington Electricity assets). The safety seminar raises awareness of safe working practices when working around the network and particular when excavating in the vicinity of existing underground infrastructure.

During 2012 over 200 local contractors received training in working safely around our network.

From time to time Wellington Electricity also mails out letters to various contracting sectors, particularly in response to known infringements, regarding safety around the network.

9.1.7 Contractors Safety Booklet

Wellington Electricity has produced a safety publication targeted at civil contractors and those working near but not accessing the Wellington Electricity network. This booklet *Wellington Electricity all need to work safely* is handed to those attending safety workshops and in mail outs to various contracting sectors that interface with the network.

9.1.8 Information and Value Add Services

Wellington Electricity provides an information service to reduce the risk of public safety and damage incident assets or property. The service is available through a 24 hour freephone number.

The table below shows the number and type of information service requests over the last three years.

Information and Value Add Services	Year		
	2010	2011	2012
Service Map Requests	9,088	6,286	9,154
Cable Locations	851	2,165	6,149
Close Approach	38	95	181
Standovers	98	123	95
High Load Permits	16	25	77
High Load Escorts	4	5	7

Figure 9-1 Summary of Information Service Requests 2010-2012

Since 2010 there has been a significant increase in calls relating to cable locations. The increase is attributed primarily to commencement of the Government funded Ultra Fast Broadband (UFB) project in the Wellington Region.

9.2 Workplace Safety

9.2.1 Safety Breakfasts

Wellington Electricity regularly arranges safety breakfasts for all its contractors. The aim of these breakfasts is to highlight key safety messages and areas for improvement. The breakfasts are also used to publically recognise and celebrate examples of good safety behaviour and practice. On average over 200 people are catered for at the sessions with breakfast cooked by the Wellington Electricity asset management team.

9.2.2 Site Safety Visits

An initiative launched in 2011 provides for Wellington Electricity personnel to undertake familiarisation visits to sites where contractors were working on the network. The Site Safety Visits are used to discuss safety systems and opportunities for improvement.

During 2012, 57 Site Safety Visits were undertaken. The goal for 2013 is to get all employees into the field for a minimum of two site visits.

9.2.3 Safety Leadership Committees

Wellington Electricity holds a monthly Safety Leadership Committee meeting to monitor performance, discuss emerging trends or new issues and progress on key improvement areas.

During 2012 Wellington Electricity established a staff Health, Safety and Environmental Committee. This staff committee has accepted the task of attaining tertiary level ACC accreditation for Wellington Electricity during 2013.

9.2.4 Workplace Safety

Wellington Electricity operates a Work Type Competency (WTC) process which categorises different types of activities on the network and sets minimum requirements in terms of qualifications, knowledge and experience.

Wellington Electricity ensures its employees are trained and competent in safety matters through providing, for example,:

- CPR / First Aid refresher sessions every six months
- Restricted area access training
- Defensive driving training for all employees who drive a company vehicle

9.3 Health and Safety Performance

9.3.1 Overview

Wellington Electricity has continued to build on its strong foundations of past HSE performance and has again noted some significant improvements during 2012. In addition to those previously detailed, notable performance improvements include:

- An positive change in safety culture through an increase in the reporting of events which may have the potential to cause harm, before harm occurs (incident and near miss reporting)

- An improvement in implementing corrective actions from the reported leading indicators so that potential harm incidents are avoided

- Improving employees ability to identify non conformances through the field assessment process via a programme of on the job training and development

- Improved management, reporting and trend analysis of the field assessment process resulting in more assessments being undertaken, timelier closure of actions and a reduction in the total number of corrective actions open at any one time.

- Working with our Service Providers to review and improve their quality assurance processes.

9.3.2 Lost Time Injury Frequency

Wellington Electricity recorded its first Lost Time Injury (LTI) incidents in over two years during 2012, resulting in the LTI Frequency Rate (LTIFR) rising from zero to 12. Reviews of the LTI incidents identified a common theme of noncompliance with use of PPE. This has been addressed with the contractor concerned and also highlighted to all Wellington Electricity employees.

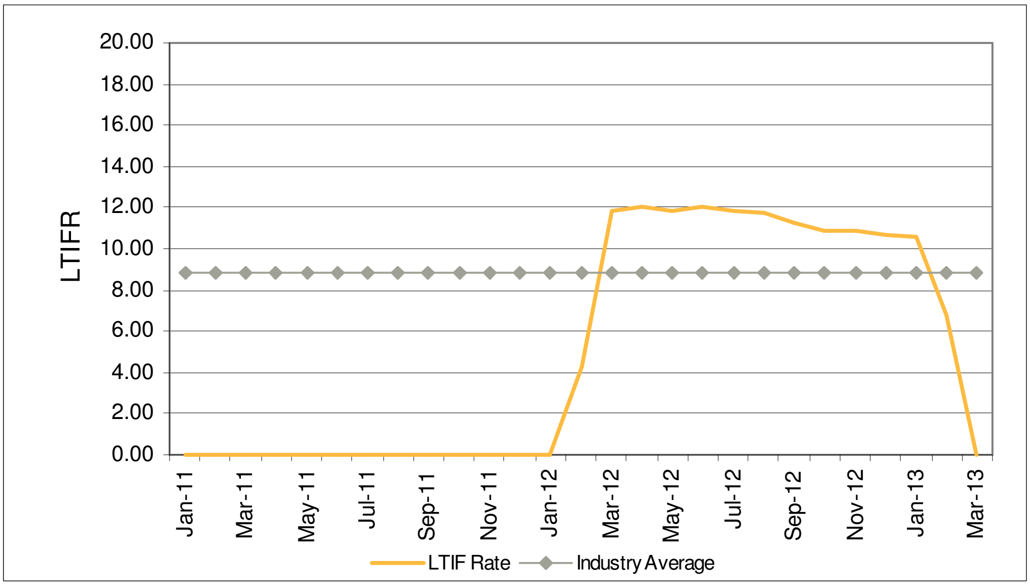

Figure 9-2 Lost Time Injury Frequency Rate

(Industry Average - EEA)

9.3.3 Incident and Near Miss Management

During 2012 Wellington Electricity continued to implement initiatives aimed at increasing reporting rates of "incidents" or "near miss" events. Total event reporting doubled from 202 events reported during 2011 to 404 events during 2012. Approximately 70% of all reported events were classified as minor, 26% were classified as moderate, whilst only 4% were of a serious nature. The total number of "near miss" events reported during 2012 was 215, a 47% increase on the previous year.

Reporting of loss events (an incident which resulted in some form of loss, damage or injury) during 2012 also significantly increased with a total of 189 incidents were reported. The majority of these were of a minor nature and very few resulted in serious loss.

9.3.4 Contractor Field Assessment

The revised Wellington Electricity Field Assessment Standard provides for the categorisation of findings from field assessments of worksites by severity and monitoring of close out times.

The majority of assessment findings were a non conformance with Wellington Electricity technical standards. There has been significant focus during 2012 on the quality of project manager field assessments. Actions include one-on-one training with the Wellington Electricity Field Compliance Assessor, attendance of a traffic management course, setting target for the number of assessments to be undertaken by project managers and improved scrutiny of the quality of assessment reports and provision of report writing and corrective action identification guidance.

It is encouraging to see a decrease in the ratio of corrective actions identified per assessment against 2011 levels. Monitoring will continue to ensure that this trend is continued and improved upon.

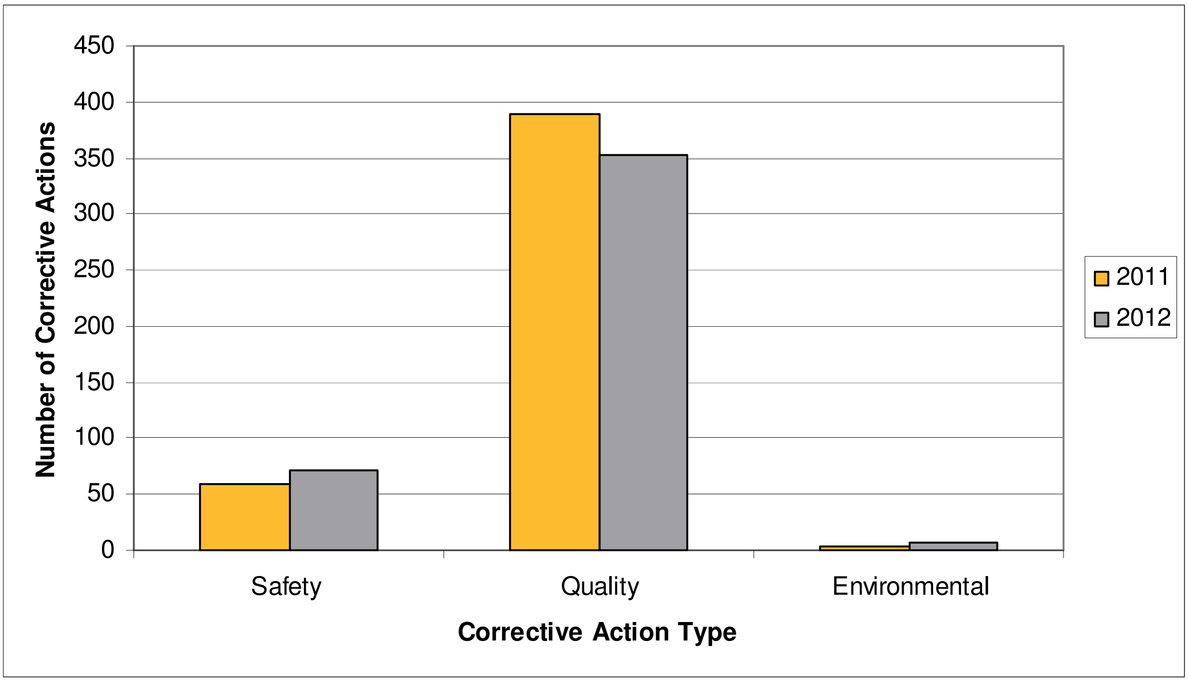

Figure 9-3 Corrective Actions arising from Assessments 2011-2012

The majority of the safety actions were a result of non compliance with Wellington Electricity PPE requirements. This ratio of event type demonstrates consistency with previous year's findings. Wellington Electricity is actively addressing this issue with its contractors.

A number of improvements have been made during 2012 these include:

- Implementing the new classification standard and improved reporting
- Improving contractors initial review and acknowledgement of assessments and corrective actions.
- Reduction in the timeframe corrective actions remain open
- Increasing the number of assessments being undertaken by Wellington Electricity Project Managers.

During 2013 focus will be placed on the following areas to further improve performance:

- Continue to increase the timeliness of close out of assessments
- Reduce the number of Corrective Actions identified
- Focus on the reduction of the high classification events.

9.3.5 Continual Improvement

Continual improvement in managing health and safety at Wellington Electricity involves ongoing review of health and safety related documents and the document management system to ensure they are aligned to current business practice and requirements.

9.3.6 Industry Led Safety Initiatives

Wellington Electricity is a member of the Electricity Engineers Association (EEA) and supports the initiatives the EEA undertakes in providing leadership, expertise and information on technical, engineering and safety issues across the NZ electricity industry.

During 2012 Wellington Electricity supported the Field Service Provider (Northpower) through the EEA led Safety Climate Project (SCP). The SCP is an improvement process based on management engagement with employees around their perception of their safety experience. The SCP has also provided valuable industry safety benchmarks and feedback which is helping the industry drive improvements in work place health and safety.

9.4 Environmental Performance

Wellington Electricity received no environmental infringement notices from TLAs during the period since the last AMP was disclosed. Wellington Electricity routinely monitors the activities of contractors working on its network. Inspections or assessments are predominantly undertaken by a Field Assessor and the team of Project Managers.

Wellington Electricity undertakes field assessments of Contractors work sites as part of the QSE compliance regime. Field assessments comprise both work in progress and completed works for compliance with Health & Safety and quality control standards. These assessments identify areas for improvement for the contractors to comply with we* standards and QSE outcomes

9.5 Territorial Local Authorities

Wellington Electricity works Territorial Local Authorities (TLAs) as stakeholders who engage or have some responsibility for contractors and other service providers that interface with the Wellington Electricity Network. Wellington Electricity aims to prevent building encroachment on the network, safer reinstatement in road reserves, improved traffic management outcomes and a better understanding of where it can mitigate risks to the public.

10 Performance Evaluation

10.1 Review of Progress Against the Previous AMP

The following table provides a comparison of forecast financial performance against actual for the previous financial year (1 April 2011 to 31 March 2012). The variance for CAPEX was -13.5% and the OPEX variance was -12.7%.

Category	Actual	Forecast	% Variance	
Capital Expenditure: Customer Connection	6,666	8,137	-18.1%	Note 1
Capital Expenditure: System Growth	2,532	3,786	-33.1%	Note 2
Capital Expenditure: Asset Replacement and Renewal	13,518	13,880	-2.6%	
Capital Expenditure: Reliability, Safety and Environment	653	665	-1.8%	
Capital Expenditure: Asset Relocations	643	1,295	-50.3%	Note 3
Subtotal - Capital Expenditure (CAPEX)	**24,011**	**27,763**	**-13.5%**	
Operational Expenditure: Routine and Preventative Maintenance	5,860	6,021	-2.7%	
Operational Expenditure: Refurbishment and Renewal Maintenance	625	674	-7.3%	
Operational Expenditure: Fault and Emergency Maintenance	3,802	5,083	-25.2%	Note 4
Subtotal - Operational Expenditure on asset management (OPEX)	**10,287**	**11,778**	**-12.7%**	
Total direct expenditure on distribution network	**34,298**	**39,541**	**-13.3%**	

Figure 10-1 Financial Performance for 2011/2012

The following notes explain the variance of Actual to Forecast (from the previous plan) in the financial performance table:

Note 1: Capital Expenditure: Customer Connection

The variance compared to forecast is due to lower than expected connection activity with overall ICP numbers remaining relatively stable. The Wellington regions economic growth (GDP) has been lower than expected at near flat levels in recent times. As reported in Section 5, building consents and subdivision developments have declined.

Note2: Capital Expenditure: System Growth

The variance compared to forecast reflects the lower level of capacity investment due to lower than expected rates of customer growth, and also the timing of several larger 11kV reinforcement projects.

Note 3: Capital Expenditure: Asset Relocations

The variance compared to forecast is also due to a major customer postponing work and delays on several large infrastructure projects resulting in lower relocations in 2012.

Note 4: Operational Expenditure: Fault and Emergency Maintenance

The variance compared to forecast is due to less incident related maintenance on the network as a result of fewer faults occurring on the network and lower costs due to the renegotiation of the Field Services Agreement.

Variance Assumptions

To ensure comparability, the variance analysis is based on the following information prepared by Wellington Electricity Lines Limited in accordance with the Electricity Distribution (Information Disclosure) Requirements 2008:

- Actual values are sourced from the Financial disclosures for the year ending 31 March 2012, prepared in December 2012; and
- Forecast values are sourced from the Asset Management Plan for the year beginning 1 April 2011, prepared in March 2011.

10.2 Evaluation of Performance against Target

The service targets that Wellington Electricity has adopted are described in detail in Section 4 (Service Levels). These targets include:

- Network reliability (SAIDI, SAIFI)
- Contact Centre service levels
- Power restoration times
- Faults per 100 circuit-km.

10.2.1 SAIDI & SAIFI

The comparison of target and actual SAIDI and SAIFI for the year 2011/2012 is provided below.

	Target 2011/12	Actual 2011/12	Variance
SAIDI	40.74	45.879	12.41%
SAIFI	0.60	0.735	19.00%

Figure 10-2 Network Reliability Performance for 2011/2012

The targets for 2011/12 were set based on the historic averages of SAIDI and SAIFI reliability data for the period 2004 to 2009. As discussed in Section 7, Wellington Electricity has exceeded its reliability limits for SAIDI and SAIFI in the 2011/12 regulatory year. This is illustrated in the SAIDI graph for the period since 2004 which shows the actual network performance. The graph shows that SAIDI performance is relatively steady but with a trend upwards in the past few years as a result of an increase in high impact events such as extreme weather.

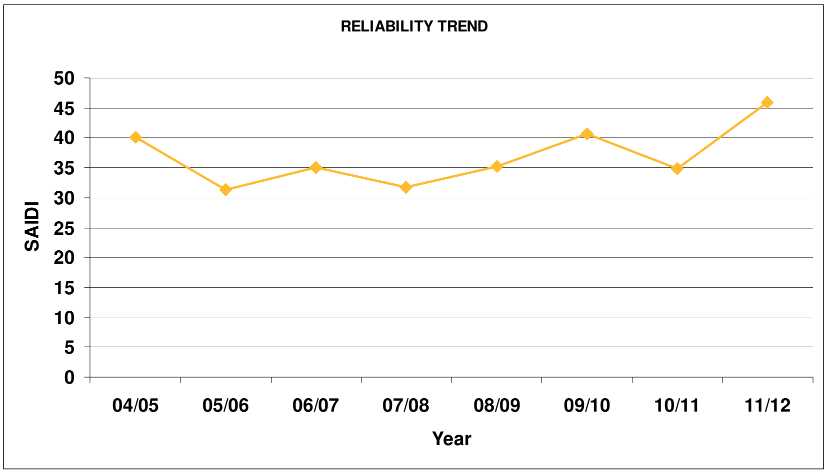

Figure 10-3 Historical SAIDI for Wellington Network 2004 to 2012

10.2.2 Contact Centre Service Level

The following tables indicate that the Contact Centre is providing a high level of service supported by positive customer experience and high levels of retailer satisfaction.

A - General Contact Centre Service Levels

SL	Service Element	Target	Actual 2011/12
A1	Overall Service Level	80%	95.9%
A2	Call response	20 seconds	17 seconds
A3	Missed calls	4%	2.3%

Figure 10-4 General Contact Centre Service Performance for 2011/2012

B - Customer Experience

SL	Service Element	Target	Actual 2011/12
C1	Specific Contact Centre experience	80%	88.6%

Figure 10-5 Contact Centre Customer Experience Performance for 2011/2012

C - Energy Retailer Satisfaction

SL	Service Element	Target	Actual 2011/12
D1	Overall retailer satisfaction with Contact Centre performance	80%	94%

Figure 10-6 Contact Centre Retailer Satisfaction Performance for 2011/2012

10.2.3 Power Restoration Time

	Less than 3 hours	More than 3 hours	More than 6 hours
Maximum time to restore power	71.54%	14.23%	14.23%

Figure 10-7 Power Restoration Time Performance for 2011/12

10.2.4 Faults per 100 Circuit-km

	Target 2011/12	Actual 2011/12
Faults per 100 circuit-km	12.0	13.30

Figure 10-8 Faults per 100 Circuit-km Performance for 2011/2012

This figure is higher than target as a result of increased interference with the network (third party strikes) and increased occurrences of adverse weather during the period. For discussion regarding the actual faults per 100 circuit-km being higher than targeted refer to Section 7 (Network Performance)

10.3 Gap Analysis

During the past year, Wellington Electricity has continued the review of its asset management strategy and practices. Progress against the gaps identified in the last AMP is shown in the table below. Despite generally good progress, not all areas were addressed and these are being carried forward for action in 2013.

2012 Section	Item	Description – Detail from 2012 AMP and Progress Updates
2.3	New Information Disclosure requirements	Pending the outcome of the new Information Disclosure requirements by the Commerce Commission, significant changes may be required to the AMP and the asset and financial systems and data used by the business.
		Completed: This AMP has been updated to reflect the new requirements and includes the required information and schedules including the AMMAT.
2.7.5	Field Services Agreement Implementation	Building on the new Field Services Agreement implemented in 2011, ongoing development and enhancement of the asset risk based condition assessment and defect management processes with the Field Service Provider will continue. A review of the vegetation management strategy will be carried out in association with the development of a new vegetation management contract.

2012 Section	Item	Description – Detail from 2012 AMP and Progress Updates
		In Progress: Approaching the end of the second year of the Field Services Agreement, the condition assessment and defect management processes are well established and all parties are working towards the goal of condition based asset risk management. The vegetation management contract will be reviewed during 2013.
2.8.1	Automatic Load Control System	Following the implementation of the ENMAC SCADA/DMS system in 2011, a needs and benefits analysis will be undertaken to review the use and future options for automatic load control, as part of the overall load management / ripple strategy.
		No Progress: Pricing has been obtained for possible replacements of the load control system. Focus on the relocation of the NCR to Petone took priority over the replacement work. A second load control terminal has been installed to provide redundancy in the mean time.
2.8.1	Maintenance Management System	Ongoing development of the business rules and processes to drive the development and implementation of an integrated maintenance management system and to consider replacement of the maintenance database with a proprietary maintenance management system.
		In Progress: During 2012 there was considerable development of the Access based Maintenance Management System, as well as a scope of work developed for a SAP PM trial which will occur in 2013.
2.8.3	Data validity and improvement	Following on from data cleansing and data quality improvement work carried out in 2011, further initiatives are underway to address the data validity for both the ICP and GIS data within the Wellington Electricity information systems. Leverage from the processes provided within the Field Services Agreement assist in the filling of data gaps and general cleansing of the asset data.
		In Progress: A significant improvement has been made to the quality of the GIS data including updating the LV connectivity, ICP connection data and nameplate data from primary plant such as switchgear and transformers. Completion of data collection is expected in 2014 however connectivity updates may be ongoing.
2.9.1	Maintenance and Defect Process	Further enhancements to the maintenance database will provide a greater analysis of defects, including the monitoring and detailed reporting of completed defects and aging defects. Improvements to reporting will be made during 2012, including a revision of the process to monitor defects and field service delivery of corrective actions.

2012 Section	Item	Description – Detail from 2012 AMP and Progress Updates
		Completed: The Maintenance Management System has been upgraded with new reporting functions to allow the scheduling of preventative maintenance tasks, and to report on defects, aging defects and overdue defects.
3.4	Spares Management	Following implementation in 2011 of the spares management policy, work is required in 2012 to rationalise the spares held and procure additional spares as required.
		In Progress: Work is ongoing with the Field Services Provider to ensure spares are held and maintained in accordance with Wellington Electricity standards. Work to rationalise these spares has occurred but is not complete. Additional strategic spares have been purchased during 2012 and will be reviewed for adequacy during 2013.
5.1	Design and Construction Standards	Wellington Electricity has a range of old standards and designs from previous owners that are in the process of being reviewed, updated and compiled into a Design and Construction Manual. Design for public safety will be a key part of the review process.
		In Progress: A number of network design standards were created or updated during 2012 and a review commenced of the Overhead Construction standard drawings. This will continue through 2013 and 2014 and be extended to all construction standards.
5.2	Prioritisation of Capital Works	Ongoing enhancements to the existing processes for prioritising capital works projects, including assessment of drivers such as network risk, financial benefit and option analysis. Development and implementation of a prioritisation or ranking tool will occur during 2012.
		In Progress: The scope for a project prioritisation tool was prepared during 2012 and different options were evaluated. Further work will occur in 2013 to complete this evaluation and produce a prioritisation tool.
5.11	Network Development Plan	Wellington Electricity has developed a draft Network Development Plan to outline all the known constraints and improvements to be undertaken on the network. This will be reviewed and finalised during 2012.
		In Progress: The draft document was not substantially updated during 2012, except for the revised information that was included in the 2012 AMP. The updated plans and contents have been included in this AMP. During 2013 the Network Development Plan will be updated based on the contents of section 5 and 6 of this plan, plus additional identified areas.

2012 Section	Item	Description – Detail from 2012 AMP and Progress Updates
6	Asset Lifecycle Planning	Continue development and refinement of "whole of life" management plans for each individual asset category to develop the existing knowledge, plans and programmes of work in the lifecycle asset management section.
		In Progress: Further ideas have been developed and incorporated into the asset management processes, however these are functional and not yet at the detail level required for "whole of life" management plans.
6.4.2	Substation Building Seismic Policy	Review of Seismic Reinforcing of Buildings policy and development of a seismic reinforcing guideline standard for Wellington Electricity owned substation buildings. Development of a prioritised list of buildings for assessment and where necessary strengthening improvements to derive an investment profile for the planning period.
		Completed: A Substation Building Seismic Policy has been developed and approved and a risk-prioritised assessment of 320 pre-1976 buildings commenced. This programme of assessment is expected to be completed in early 2016.
6.4.8	Telecommunications on poles policy	Development during 2012 of a Telecommunications on poles policy to provide guidance to third parties wishing to install fibre and other communications circuits on network poles.
		In Progress: A Telecommunications on Poles technical standard has been developed and is in the final review process. This document will be approved and finalised during 2013.
6.4.14	Communications Strategy	Finalise and implement the communications strategy for development and replacement of network infrastructure communications for SCADA and Protection and other business communications needs.
		In Progress: Substantial work has been completed on the corporate and SCADA level communications systems. This includes the resolution of substation communications boundaries with the existing service provider. This work is expected to be finalised and gain CEO approval in 2013.
8.9	Specific Network Asset Risk Controls	Further development of the Risk Management Standard ISO 31000:2009 within the assessment of the inherent and residual risk of specific network asset controls
		Completed: Review of risk profiling register was completed during 2012 and submitted to the Audit and Risk Committee.

2012 Section	Item	Description – Detail from 2012 AMP and Progress Updates
8.10.1	Seismic Reinforcing of Equipment and Buildings	Review of Seismic Reinforcing of Buildings policy and the development of a seismic reinforcing guideline standard for Wellington Electricity owned substation buildings.
		In Progress: Substation Seismic Policy is approved and in use with an assessment of around 320 substation buildings underway. A scope has been written for the reinforcing guideline and this document is expected to be completed during 2013.
8.10.2	33kV Overhead Emergency Corridors	Completion of the planning and design of the defined 33kV overhead line emergency corridors and appropriate support structures
		In Progress: 50% of routes identified have had detailed line designs created, with the balance to be completed during 2013. Consultation with the Wellington City council will occur during 2013 to discuss the routes and use of temporary overhead lines.
8.12	Emergency Response Plans	Ongoing testing and enhancement of the Emergency Response Plans with a focus on the Crisis Management Plan and the IT Recovery Plan
		Completed: During 2012 both plans (Crisis Management and IT Recovery) were tested and identified improvements will be made in advance of a re-test during 2013.
9.5	Health, Safety and Environmental Improvements	Asbestos Management - Replacement of all asbestos lined arc chutes in the DC circuit breakers.
		Completed: The asbestos lined DC arc chutes were replaced in 2012
		Polices, Procedures and Standards – A number of documents are programmed to be reviewed this year including: Work Place Hazard Assessment, Fit for Work Policy, Environmental Management Plan.
		In Progress: The listed documents were reviewed during the year and improvements made accordingly. Further review of some standards will occur during 2013.
		Work Type Competency (WTC) Training – A number of training and assessment courses will be developed with the aim of supporting contractors in assessing the competency of their staff who are working on, or near, the Wellington Electricity network.
		In Progress: Course material for a number of work type competencies have been developed and reviewed during the year. Wellington Electricity will continue to review and improve WTC material during 2013.

2012 Section	Item	Description – Detail from 2012 AMP and Progress Updates
		3rd Party Communication – A series of presentations will be undertaken with TLAs, contractors and other stakeholders to increasing awareness of the risks associated with working on or near the network.
		Completed: Presentations were made to approximately 200 attendees (representing TLAs, contractors and other stakeholders).
		Incident Data Management, Analysis and Performance Reporting – A review of the data management requirements for incident reporting will be undertaken to identify options to improve data management and reporting systems.
		Completed: An audit of the incident reporting and management process was undertaken during 2012. Minor improvements around security of data and improved reporting were identified and actioned.
		Contractor Audit and Inspection Review –The review will look at the systems and processes supporting contractors to identify opportunities for improving contractor assurance, for sharing knowledge and eliminating any poor workplace practices.
		Completed: Wellington Electricity undertook a quality assurance audit of each of its Service Providers during the year. The audits identified a number of improvements and these are being tracked through to completion. Key areas for improvement include contractor management, internal communication / knowledge management and audit / self inspection activities.
9.6	Public Safety Management System	Completion of the SMS stage 2 audit action plan and gain certification to NZS 7901 within regulatory timeframes.
		Completed: Certification to NZS 7901 was achieved at the first attempt and within the regulatory timeframes. This certification was re-assessed in January 2013 and Wellington Electricity continues to have certification of its PSMS to this standard.

Figure 10-9 Progress on Gaps Identified in the 2012 AMP

There are still gaps and improvement initiatives that have been identified in a number of key business areas. These gaps and areas for improvement are referred to throughout the AMP in the sections where they occur and are summarised below:

Section	Item	Description
Items incomplete from the 2012 AMP brought forward		
2.7.5	Field Services Agreement Implementation	Vegetation management contract to be reviewed and implemented during 2013 for 2014 commencement
2.8.1	Automatic Load Control System	Undertake further investigation and planning into the replacement for the Foxboro automatic load control system. Preliminary work has been completed but further development around a final solution is still required. Changes to the proposed EA MUoSA may impact upon the timing and solution.
2.8.1	Maintenance Management System	Ongoing development of the Maintenance Management Database is required, and a trial of SAP is planned for 2013. It is anticipated that a full implementation of SAP PM will be scoped during 2013 for commissioning in 2014.
2.8.3	Data validity and improvement	Ongoing connection point (ICP) data validation and connectivity improvements to be made in the GIS as part of an ongoing programme, as well continuous updating of records captured during field inspections, such as nameplate data of equipment.
3.4	Spares Management	Further work to be undertaken around the recording of spares, and spares movements. Some further rationalisation of the spares held may be possible.
5.1	Design and Construction Standards	Further updates to the design and construction standard drawings will continue during 2013 and into 2014.
5.2	Prioritisation of Capital Works	Completion of a project prioritisation tool, and implementation within the business following the work undertaken in 2012.
5.11	Network Development Plan	Further enhancements to the draft Network Development Plan are required to update it with more recent development projects and new risks identified.
6.4	Asset Lifecycle Planning	Continued development of asset lifecycle plans for all asset categories.
6.4.8	Telecommunications on poles policy	Finalisation of the draft Telecommunications on Poles technical standard, and circulation to telecommunications providers who access Wellington Electricity poles.
6.4.14	Communications Strategy	Finalisation and implementation of the Communications Strategy will occur during 2013.

Section	Item	Description
8.10.1	Seismic Reinforcing of Equipment and Buildings	Ongoing assessment of nominated substation buildings in accordance with the seismic assessment programme. Consultation with regulators and stakeholders is required to determine the appropriate funding mechanism for building reinforcement.
8.10.2	33kV Overhead Emergency Corridors	Completion of designs for the remaining overhead subtransmission routes, and consultation with Wellington City Council to gain approval for these routes.
9	Health, Safety and Environmental Improvements	Further review of corporate QSE policies Completion of development of Work Type Competency training programmes and material
New items identified from this AMP		
2.13	Capability to Deliver	To resource map key projects and work items identified in this plan against available internal and external resources.
5.7.6	Step Load Changes	Presently only step load increases are covered in this section, and Wellington Electricity does not identify or record major step decreases in load as no formal notification process exists between consumers, retailers and Wellington Electricity.
5.9	Investment in DG schemes	Wellington Electricity will investigate further whether there is benefit in investing in Distributed Generation schemes on the network to offset investment to address security and capacity risks.
5.11	Emerging Technology	New technologies such as local storage schemes need to be investigated for possible benefits to the network.
5.12	Transmission Connection Assets	Wellington Electricity is exploring opportunities to transfer ownership of Connection Assets from Transpower. There is potential opportunity to take ownership of sites such as Melling, Gracefield and Pauatahanui (should Paraparaumu be supplied from 220kV as proposed) as these sites supply only Wellington Electricity and may be better placed under EDB ownership.
6.4.2	Subtransmission Cable Replacement Strategy	Further work is required to optimise the replacement of fluid filled subtransmission cables and to show year on year length changes between solid and fluid filled cable insulation types in section 3 and 6
6.4.4	Zone transformer relocation plan	A plan will be investigated to show where zone substation power transformers can be relocated to address capacity and condition concerns. Relocation may be a viable alternative to replacement where the risk profile remains at an acceptable level.

Section	Item	Description
6.4.8	Load Control Replacement Strategy	Wellington Electricity needs evaluate the strategy for replacing load control assets, including the DC Bias system as some system components are showing end of life failure modes. Changes proposed by the EA MUoSA may impact upon the decision Wellington Electricity will make regarding this equipment.
6.4.9	Poles and Overhead Lines	Further work to be completed around below ground life extension techniques for poles to optimise the repair vs. replacement decision for unserviceable poles.
6.5	Operating Expense by Asset Category	Wellington Electricity are working to improve OPEX breakdowns for each asset category, particularly in reactive (faults) and corrective maintenance categories as a history develops, asset category splits of OPEX for future years will be able to be forecast with greater certainty.
7.5.4	Worst Performing feeders – reliability improvement programme	Cable diagnostic testing needs to occur to understand the long term performance expectations of worst performing feeders with underground cable sections. Identification of overhead equipment failure types is understood, however cable performance is a work in progress.
8.9	Specific Network Risks	To provide summary of network risk controls in place.
8.12	Emergency Response Plans	Continue to build capability with internal and external staff and field service contractors via simulation testing of plans. Develop lifelines interdependencies and mutual aid agreements.

Figure 10-10 Gaps and Improvements Identified in the 2013 AMP

Wellington Electricity aims to address these gaps and areas for improvement over the year ahead.

10.4 Evaluation of AMMAT Results

From the completed Asset Management Maturity Assessment Tool (AMMAT) provided as a schedule to this plan, the assessed result was effective, with a final score of 2.7. Minor inconsistencies or gaps identified were in the areas of Asset Data, Quality and Process Level Control. The following graph extracted from the AMMAT gives a summary of the results.

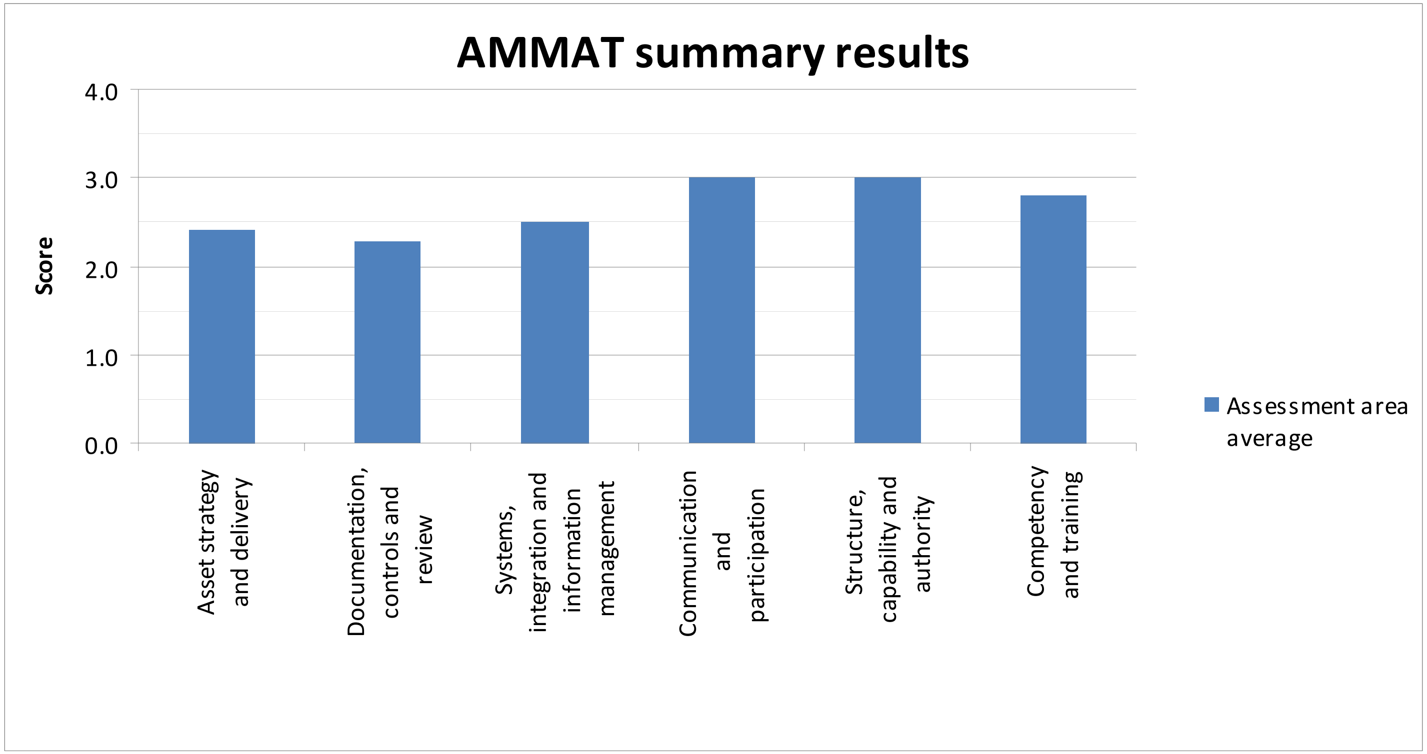

Figure 10-11 Summary of the AMMAT Assessment 2013

The following areas were identified in the AMMAT through self-assessment, to be lower than Maturity level 3 (taken to be the target level of the business), and a brief description of the development strategy to get from the present maturity level to level 3 is provided in the table. Development beyond Maturity level 3 for individual aspects of the AMMAT will be considered by Wellington Electricity where the need is clear, cost effective and justifiable.

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
10	Asset management strategy	What has the organization done to ensure that its asset management strategy is consistent with other appropriate organizational policies and strategies, and the needs of stakeholders?	Some of the linkages between the long-term asset management strategy and other organizational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	The WE AMP considers asset strategy. The work is advanced, however there are currently gaps with regard to all asset categories and long term strategy for all assets.	2	Development of long term strategies for all asset categories will occur during 2013 and 2014.
11	Asset management strategy	In what way does the organization's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organization has stewardship?	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	Lifecycle strategy has been introduced for the major asset classes such as switchgear, subtransmission cables, poles and transformers, but remains incomplete for all asset classes.	2	As per question 10 above, development of lifecycle asset management strategies will occur during 2013 and 2014.
26	Asset management plan(s)	How does the organization establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organization is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	The organization is in the process of putting in place comprehensive, documented asset management plans that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	2	As per question 10 above, development of lifecycle asset management strategies will occur during 2013 and 2014.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Whilst significant controls are in place to manage the delivery of AM activities within the outsourced contractors, there are gaps in AM strategy communication and contractor process control. In particular these are with maintenance and reactive fault quality assurance management.	2	During 2013 WE will work to improve the control of outsourced activities focussing on quality management practices to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy.

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The AMP describes the key attributes of an asset management system however there are gaps in the overall completeness of that system. An effective architectural overview document would provide this visibility and connectivity.	2	An overview document of the asset management system will be developed and included in the next AMP.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	Various systems are in place for the management of AM information and data. The primary system is GIS. A business review is currently being carried out for the adoption of a proprietary asset management system such as SAP.	2	Through the investigation of a SAP PM maintenance system, the information systems needs will be thoroughly assessed and documented.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	Various systems are in place for the management of AM information and data. The primary systems are GIS and MMS. A business review is currently being carried out for the adoption of a proprietary asset management system such as SAP.	2	Through the investigation of a SAP PM maintenance system, the information systems needs will be thoroughly assessed and documented.

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
69	Risk management process(es)	How has the organization documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organization is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Asset related risks have been implemented as part of the risk management framework. There are however gaps surrounding the risks associated with each stage of the lifecycle of assets.	2	Through the development of the lifecycle asset strategies for all categories that will be developed during 2013 and 2014, a summary of all asset related risks can be compiled and provided in future plans where appropriate.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	The outputs from the risk management process are included for the requirement to control the risk. Work is ongoing to develop a long term resource strategy based on the asset management forecast which is derived from asset knowledge, risk management and future work programmes.	2	Development of a resource map will occur during 2013 for driving the resource strategy for future years.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	There are AM policies, procedures and processes in place which deal with the management of assets during the design to commissioning phase. There are procedures to determine how these are derived and prioritised within the asset management plan. There are gaps covering projects accelerated and not included within the AMP, together with works management quality monitoring. These gaps are being addressed.	2	There are gaps in some areas of the lifecycle of the assets, such as standards relating to procurement, construction, testing and operation and maintenance. Development of identified undeveloped standards together with works management quality monitoring.

No	Function	Question	Maturity Level Comment	Evidence - Summary	Score	Development Strategy
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	Whilst the audit program is mature and targeted to areas of risk and quality delivery, there are some areas of the asset management system and process which are not covered within the current audit regime	2	Extend audit regime to cover identified areas of the asset management process which are not presently covered
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	Continual improvement and optimisation of asset health, costs and risks across the whole asset lifecycle are in place although need to be finalised and fully implemented and embedded. Continuous improvement processes are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	2	Review of the effectiveness of the newly developed strategies identified above. Provision of feedback into the strategy documents to ensure effectiveness.

Appendix A Information Schedules

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	5,318	6,251	6,670	7,417	8,171	7,740	7,602	8,189	8,547	8,974	10,055
11	System growth	3,764	8,174	8,166	7,934	8,661	6,746	6,679	8,290	8,303	8,171	7,961
12	Asset replacement and renewal	17,767	17,798	18,683	18,864	19,491	25,467	27,310	26,230	26,207	27,053	29,417
13	Asset relocations	935	956	1,033	1,171	1,245	1,192	1,207	1,310	1,341	1,388	1,522
14	Reliability, safety and environment:											
15	Quality of supply	481	406	322	25	27	31	31	31	32	33	34
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	497	432	493	619	668	748	758	763	787	811	833
18	**Total reliability, safety and environment**	978	838	815	644	695	779	789	794	819	844	867
19	**Expenditure on network assets**	28,763	34,018	35,367	36,030	38,263	41,924	43,586	44,813	45,217	46,429	49,821
20	Non-network assets	578	1,856	1,630	1,162	1,142	1,113	1,194	1,209	1,225	1,241	1,258
21	**Expenditure on assets**	29,341	35,874	36,997	37,192	39,405	43,036	44,781	46,023	46,442	47,670	51,079
22												
23	*plus* Cost of financing	309	368	376	385	394	402	411	421	430	440	450
24	*less* Value of capital contributions	4,564	4,188	4,184	4,383	4,469	4,594	4,797	4,931	4,975	5,106	5,482
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	25,086	32,054	33,189	33,194	35,330	38,845	40,395	41,513	41,898	43,004	46,047
28												
29	Value of commissioned assets	24,579	34,239	33,189	33,194	35,330	38,845	40,395	41,513	41,898	43,004	46,047
30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
32		**$000 (in constant prices)**										
33	Consumer connection	5,318	6,113	6,380	6,938	7,475	6,925	6,652	7,008	7,153	7,346	8,049
34	System growth	3,764	7,994	7,811	7,422	7,924	6,035	5,844	7,095	6,949	6,688	6,373
35	Asset replacement and renewal	17,767	17,407	17,869	17,646	17,831	22,786	23,897	22,447	21,934	22,143	23,548
36	Asset relocations	935	935	988	1,095	1,139	1,067	1,056	1,121	1,123	1,136	1,218
37	Reliability, safety and environment:											
38	Quality of supply	481	397	308	24	25	27	27	27	27	27	27
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	497	422	472	579	611	670	664	653	658	664	667
41	**Total reliability, safety and environment**	978	820	780	602	636	697	691	679	685	691	694
42	**Expenditure on network assets**	28,763	33,269	33,828	33,704	35,004	37,510	38,139	38,350	37,844	38,003	39,882
43	Non-network assets	578	1,815	1,559	1,087	1,045	995	1,045	1,035	1,025	1,016	1,007
44	**Expenditure on assets**	29,341	35,084	35,387	34,791	36,049	38,505	39,184	39,385	38,869	39,019	40,889
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

57			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
58		for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
59	**Difference between nominal and constant price forecasts**		**$000**										
60	Consumer connection		-	138	290	479	696	815	950	1,181	1,394	1,629	2,006
61	System growth		-	180	355	512	738	710	835	1,196	1,354	1,483	1,588
62	Asset replacement and renewal		-	392	813	1,218	1,660	2,681	3,413	3,783	4,273	4,909	5,868
63	Asset relocations		-	21	45	76	106	126	151	189	219	252	304
64	Reliability, safety and environment:												
65	Quality of supply		-	9	14	2	2	3	4	4	5	6	7
66	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment		-	10	21	40	57	79	95	110	128	147	166
68	**Total reliability, safety and environment**		-	18	35	42	59	82	99	114	134	153	173
69	**Expenditure on network assets**		-	749	1,539	2,327	3,258	4,414	5,447	6,463	7,373	8,426	9,939
70	Non-network assets		(0)	41	71	75	97	117	149	174	200	225	251
71	**Expenditure on assets**		(0)	790	1,610	2,401	3,356	4,531	5,596	6,638	7,573	8,651	10,190
72													

73			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
74	**11a(ii): Consumer Connection**							
75	*Consumer types defined by EDB**		**$000 (in constant prices)**					
76	Substation		2,266	3,287	3,175	2,696	2,856	2,419
77	Subdivision		1,202	1,150	1,449	2,259	2,462	2,407
78	High Voltage Connection		229	32	24	24	24	24
	Residential customers		1,246	1,566	1,674	1,901	2,076	2,018
79	Generation connections		76	-	-	-	-	-
80	Public lighting		297	78	57	57	57	57
81	**include additional rows if needed*							
82	**Consumer connection expenditure**		5,318	6,113	6,380	6,938	7,475	6,925
83	*less* Capital contributions funding consumer connection		3,723	3,317	3,242	3,321	3,311	3,329
84	**Consumer connection less capital contributions**		1,595	2,796	3,138	3,617	4,164	3,596
85	**11a(iii): System Growth**							
86	Subtransmission		-	-	-	-	-	-
87	Zone substations		2,696	5,725	5,594	5,315	5,675	4,322
88	Distribution and LV lines		-	-	-	-	-	-
89	Distribution and LV cables		945	2,006	1,960	1,863	1,989	1,515
90	Distribution substations and transformers		124	263	257	244	260	198
91	Distribution switchgear		-	-	-	-	-	-
92	Other network assets		-	-	-	-	-	-
93	**System growth expenditure**		3,764	7,994	7,811	7,422	7,924	6,035
94	*less* Capital contributions funding system growth							
95	**System growth less capital contributions**		3,764	7,994	7,811	7,422	7,924	6,035

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18

11a(iv): Asset Replacement and Renewal

$000 (in constant prices)

Subtransmission	582	570	586	578	584	747
Zone substations	2,562	2,510	2,576	2,544	2,571	3,285
Distribution and LV lines	4,192	4,107	4,216	4,163	4,207	5,376
Distribution and LV cables	699	684	703	694	701	896
Distribution substations and transformers	1,525	1,494	1,534	1,515	1,531	1,956
Distribution switchgear	5,857	5,738	5,891	5,817	5,878	7,511
Other network assets	2,350	2,303	2,364	2,334	2,359	3,014
Asset replacement and renewal expenditure	17,767	17,407	17,869	17,646	17,831	22,786
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	17,767	17,407	17,869	17,646	17,831	22,786

11a(v):Asset Relocations

*Project or programme**						
Asset relocations	935	935	988	1,095	1,139	1,067
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other asset relocations projects or programmes						
Asset relocations expenditure	935	935	988	1,095	1,139	1,067
less Capital contributions funding asset relocations	841	778	760	779	777	781
Asset relocations less capital contributions	94	157	228	316	362	286

11a(vi):Quality of Supply

*Project or programme**						
Programme - Fault Passage Indicators	22	30	44	24	24	27
Wainuiomata Coast Rd - Upgrade	188	150	199	-	-	-
Karori - Reliability improvement	159	122	37	-	-	-
Ngauranga - Reconductoring	112	72	-	-	-	-
[Description of material project or programme]						
**include additional rows if needed*						
All other quality of supply projects or programmes	-	24	28	(0)	0	(0)
Quality of supply expenditure	481	397	308	24	25	27
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	481	397	308	24	25	27

11a(vii): Legislative and Regulatory

*Project or programme**						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other legislative and regulatory projects or programmes						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environmer

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18
*Project or programme**	$000 (in constant prices)					
Programme - Earthing Compliance	299	281	225	225	225	169
Programme - Lock Replacements	83	38	-	-	-	-
Programme - Asbestos Removal	83	58	83	83	83	63
Programme - LV Dennis Panel Covers	33	-	-	-	-	-
Programme - Local Authority compliance	-	20	121	270	302	438
**include additional rows if needed*						
All other reliability, safety and environment projects or programmes	-	25	43	-	-	-
Other reliability, safety and environment expenditure	497	422	472	579	611	670
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	497	422	472	579	611	670

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Routine expenditure						
*Project or programme**						
Control Room	30	6	-	-	-	-
Software	392	904	706	682	724	743
Contact Centre	15	-	-	-	-	-
Communication Provider	142	866	811	405	320	253
**include additional rows if needed*						
All other routine expenditure projects or programmes	-	39	42	0	0	0
Routine expenditure	578	1,815	1,559	1,087	1,045	995
Atypical expenditure						
*Project or programme**						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other atypical projects or programmes						
Atypical expenditure	-	-	-	-	-	-
Non-network assets expenditure	578	1,815	1,559	1,087	1,045	995

Company Name: **Wellington Electricity**
AMP Planning Period: **1 April 2013 – 31 March 2023**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
9	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
10	Service interruptions and emergencies	3,766	3,889	4,116	4,356	4,498	4,646	4,798	4,955	5,117	5,284	5,457
11	Vegetation management	1,126	1,172	1,249	1,322	1,375	1,431	1,489	1,549	1,611	1,676	1,744
12	Routine and corrective maintenance and inspection	6,655	6,918	7,368	7,798	8,106	8,426	8,759	9,105	9,465	9,839	10,228
13	Asset replacement and renewal	625	650	693	734	763	794	826	859	894	930	968
14	**Network Opex**	12,173	12,629	13,426	14,209	14,743	15,296	15,871	16,468	17,087	17,730	18,397
15	System operations and network support	3,968	4,105	4,352	4,613	4,773	4,938	5,109	5,285	5,468	5,658	5,854
16	Business support	13,013	14,021	15,011	16,087	16,861	17,704	18,628	19,645	20,592	21,609	22,703
17	**Non-network opex**	16,981	18,126	19,363	20,700	21,633	22,642	23,737	24,930	26,060	27,267	28,557
18	**Operational expenditure**	29,153	30,755	32,789	34,909	36,376	37,939	39,608	41,398	43,148	44,997	46,954

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
21		$000 (in constant prices)										
22	Service interruptions and emergencies	3,766	3,804	3,937	4,075	4,115	4,157	4,198	4,240	4,282	4,325	4,369
23	Vegetation management	1,126	1,146	1,195	1,236	1,258	1,280	1,303	1,325	1,349	1,372	1,396
24	Routine and corrective maintenance and inspection	6,655	6,766	7,048	7,294	7,415	7,539	7,664	7,792	7,922	8,053	8,188
25	Asset replacement and renewal	625	636	663	686	698	710	723	735	748	761	775
26	**Network Opex**	12,173	12,352	12,842	13,291	13,487	13,686	13,888	14,093	14,301	14,512	14,727
27	System operations and network support	3,968	4,014	4,162	4,315	4,366	4,418	4,470	4,523	4,577	4,631	4,686
28	Business support	13,013	13,712	14,358	15,048	15,425	15,840	16,300	16,811	17,234	17,688	18,174
29	**Non-network opex**	16,981	17,727	18,520	19,364	19,791	20,258	20,771	21,334	21,811	22,319	22,860
30	**Operational expenditure**	29,153	30,078	31,362	32,655	33,278	33,944	34,658	35,427	36,112	36,831	37,587
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
	Insurance	1,102	1,267	1,457	1,675	1,927	2,216	2,548	2,930	3,223	3,546	3,900

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 13	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions and emergencies	-	86	179	281	383	489	600	715	834	959	1,089
43	Vegetation management	-	26	54	85	117	151	186	223	263	304	348
44	Routine and corrective maintenance and inspection	-	152	321	504	690	887	1,095	1,313	1,543	1,786	2,040
45	Asset replacement and renewal	-	14	30	47	65	84	103	124	146	169	193
46	**Network Opex**	-	278	584	918	1,255	1,611	1,984	2,375	2,786	3,218	3,670
47	System operations and network support	-	90	189	298	406	520	638	762	892	1,027	1,168
48	Business support	-	309	653	1,039	1,436	1,864	2,328	2,833	3,358	3,922	4,529
49	**Non-network opex**	-	399	843	1,337	1,842	2,384	2,967	3,596	4,249	4,948	5,697
50	**Operational expenditure**	-	677	1,427	2,254	3,098	3,994	4,950	5,971	7,036	8,166	9,367

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref											
7					**Asset condition at start of planning period (percentage of units by grade)**						
8	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	1.00%	4.00%	25.00%	50.00%	20.00%	3	5.00%
11	All	Overhead Line	Wood poles	No.	5.00%	15.00%	40.00%	20.00%	20.00%	3	20.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	1.00%	98.00%	1.00%	-	3	1.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	20.50%	79.50%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	15.00%	85.00%	-	-	3	15.00%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	10.00%	20.00%	70.00%	-	-	3	30.00%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	5.00%	95.00%	-	-	3	2.00%
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	75.00%	25.00%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	100.00%		-	-	3	100.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	-	-	N/A	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	25.00%	75.00%	-	-	3	10.00%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	N/A	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	5.00%	10.00%	70.00%	15.00%	-	3	10.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	N/A	-

					Asset condition at start of planning period (percentage of units by grade)						
42											
43	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
44											
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	5.00%	10.00%	75.00%	10.00%	-	3	4.00%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.00%	10.00%	84.00%	5.00%		3	1.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	1.00%	10.00%	84.00%	5.00%		3	-
48	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	N/A	-
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	2.00%	8.00%	5.00%	85.00%		3	-
50	HV	Distribution Cable	Distribution UG PILC	km	2.00%	8.00%	80.00%	10.00%		3	2.00%
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	4.00%	16.00%	60.00%	20.00%	-	3	20.00%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5.00%	15.00%	70.00%	10.00%	-	3	10.00%
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5.00%	10.00%	66.00%	19.00%	-	3	10.00%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	5.00%	10.00%	75.00%	10.00%		3	15.00%
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	5.00%	10.00%	75.00%	10.00%		3	3.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	2.00%	8.00%	45.00%	45.00%		3	2.00%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	2.00%	8.00%	65.00%	25.00%		3	3.00%
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	N/A	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	5.00%	10.00%	70.00%	15.00%		3	3.00%
61	LV	LV Line	LV OH Conductor	km	2.00%	13.00%	75.00%	10.00%		3	1.00%
62	LV	LV Cable	LV UG Cable	km	1.00%	9.00%	60.00%	30.00%	-	3	2.00%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	5.00%	10.00%	80.00%	5.00%	-	1	2.00%
64	LV	Connections	OH/UG consumer service connections	No.	5.00%	10.00%	80.00%	5.00%	-	1	2.00%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	5.00%	10.00%	80.00%	5.00%	-	3	10.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	5.00%	10.00%	70.00%	15.00%		3	10.00%
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	N/A	-
68	All	Load Control	Centralised plant	Lot	5.00%	15.00%	70.00%	10.00%	-	3	5.00%
69	All	Load Control	Relays	No.	-	-	-	-	-	N/A	-
70	All	Civils	Cable Tunnels	km	-	-	100.00%	-	-	3	-

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2013 – 31 March 2023**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 ### 12b(i): System Growth - Zone Substations

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	8 Ira St	17.0	24	N-1	9	71%	24	77%	No constraint within +5 years	
10	Brown Owl	15.5	23	N-1	7	67%	23	72%	No constraint within +5 years	
11	Evans Bay	15.8	24	N-1	11	66%	24	73%	No constraint within +5 years	
12	Frederick St	29.2	36	N-1	13	81%	36	90%	Subtransmission circuit	High Demand, Capacity shortfall
13	Gracefield	12.6	23	N-1	12	55%	23	59%	No constraint within +5 years	
14	Hataitai	17.6	23	N-1	11	77%	23	82%	No constraint within +5 years	
15	Johnsonville	18.2	23	N-1	9	79%	23	74%	Subtransmission circuit	High Demand growth north east of Johnsonville - Development of new Sub-division
16	Karori	17.3	24	N-1	7	72%	24	78%	No constraint within +5 years	
17	Kenepuru	11.0	23	N-1	9	48%	23	57%	No constraint within +5 years	
18	Korokoro	11.9	23	N-1	11	52%	23	86%	No constraint within +5 years	
19	Maidstone	15.0	22	N-1	12	68%	22	74%	No constraint within +5 years	
	Mana-Plimmerton	18.9	16	N-1	12	118%	16	128%	Transformer	Capacity Shortfall
	Moore St	25.4	36	N-1	14	71%	36	82%	No constraint within +5 years	
	Naenae	15.5	23	N-1	11	67%	23	73%	No constraint within +5 years	
	Nairn St	17.5	30	N-1	16	58%	30	71%	No constraint within +5 years	
	Ngauranga	12.8	12	N-1	10	107%	12	115%	Transformer	High Demand growth north east of Ngauranga and in Johnsonville - Development of new Sub-division
	Palm Grove	27.5	24	N-1	13	115%	24	125%	Subtransmission circuit	Capacity Shortfall
	Petone	10.5	20	N-1	10	53%	20	-	No constraint within +5 years	
	Porirua	17.7	20	N-1	14	89%	20	95%	No constraint within +5 years	
	Seaview	13.4	22	N-1	12	61%	22	76%	No constraint within +5 years	
20	Tawa	14.3	16	N-1	13	89%	16	109%	Transformer	Due to high demand growth south of Tawa (Grenada Village)
21	The Terrace	29.7	36	N-1	21	83%	36	90%	No constraint within +5 years	
22	Trentham	14.9	23	N-1	10	65%	23	70%	No constraint within +5 years	
23	University	25.8	24	N-1	21	108%	24	119%	Subtransmission circuit	Capacity Shortfall
24	Waikowhai	16.2	19	N-1	10	85%	19	90%	No constraint within +5 years	
25	Wainuiomata	17.0	23	N-1	3	74%	23	80%	No constraint within +5 years	
26	Waitangirua	14.8	16	N-1	11	93%	16	98%	No constraint within +5 years	
27	Waterloo	18.0	23	N-1	14	78%	23	85%	No constraint within +5 years	
28	[Zone Substation_20]					-			[Select one]	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

30 ### 12b(ii): Transformer Capacity

sch ref		(MVA)
32	Distribution transformer capacity (EDB owned)	1,350
33	Distribution transformer capacity (Non-EDB owned)	
34	**Total distribution transformer capacity**	1,350
35		
36	**Zone substation transformer capacity**	1,138

Company Name	**Wellington Electricity**
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SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
11	*Consumer types defined by EDB**							
12	Domestic		717	737	752	760	754	759
13	Large Commercial		10	11	11	10	9	10
14	Large Industrial		1	-	-	-	-	-
	Medium Commercial		21	20	21	18	20	19
	Small Commercial		460	450	439	440	445	440
15	Small Industrial		4	3	3	3	3	3
16	Unmetered		53	45	40	35	35	35
17	**Connections total**		1,266	1,266	1,266	1,266	1,266	1,266
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		20	20	20	20	20	20
21	Installed connection capacity of distributed generation (MVA)		1	1	1	1	1	1
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
25	GXP demand		550	555	560	565	571	576
26	*plus* Distributed generation output at HV and above		2	2	2	2	2	2
27	**Maximum coincident system demand**		552	557	562	567	573	578
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**		552	557	562	567	573	578
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		2,526	2,560	2,570	2,585	2,603	2,629
32	*less* Electricity exports to GXPs		-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation		12	12	12	12	12	12
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		2,538	2,572	2,582	2,597	2,615	2,641
36	*less* Total energy delivered to ICPs		2,411	2,444	2,453	2,467	2,484	2,509
37	**Losses**		127	129	129	130	131	132
38								
39	**Load factor**		52%	53%	52%	52%	52%	52%
40	**Loss ratio**		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%

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Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	1.4	1.3	1.3	1.3	1.3	1.3
12	Class C (unplanned interruptions on the network)	41.8	36.3	36.3	36.3	36.3	36.3
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.01	0.01	0.01	0.01	0.01	0.01
15	Class C (unplanned interruptions on the network)	0.55	0.57	0.57	0.57	0.57	0.57

			Company Name	Wellington Electricity
			AMP Planning Period	1 April 2013 – 31 March 2023
			Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	WE has an asset management policy which is derived from the organisational vision and linked to organisational strategies, objectives and targets. WE also has a number of focused policies for the management of discrete assets which are consitent with the corporate AM policy.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	The WE AMP considers asset strategy. The work is advanced, however there are currently gaps with regard to all asset categories and long term strategy for all assets.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	Lifecycle strategy has been introduced for the major asset classes such as switchgear, subtransmission cables, poles and transformers, but remains incomplete for all asset classes.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	The organization is in the process of putting in place comprehensive, documented asset management plans that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively. It demonstrably supports business process.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The asset management plan consistently documents responsibilities for the delivery actions, and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system. Work is advanced on a long term strategic resource map relative to asset management organisational delivery requirements.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Emergency management for credible events has been planned and practiced. Further strategies for specific crisis events have been developed.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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AMP Planning Period	1 April 2013 – 31 March 2023
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Good solid accountability for Asset Management responsibility from CEO, through Network GM and through Network Team fuctional Line Managers		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	An effective process exists for determining the resources needed for asset management and that sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements. Work is advanced on a long term strategic resource map relative to asset management organisational delivery requirements.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Communication is guided through the annual AMP disclosures and through weekly and monthly performance meetings with Management teams and Contractors.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	Whilst significant controls are in place to manage the delivery of AM activities within the outsourced contractors, there are gaps in AM strategy communication and contractor process control. In particular these are with maintenance and reactive fault quality assurance management.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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		Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	We* can demonstrate that plans are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system processes.The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plans and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system. Work is advanced on a long term strategic resource map relative to asset management organisational delivery requirements.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	There is the requirement for defined levels of management / technical and AM competencies through Job Descriptions / standard Key competency requirements. These are reviewed six monthly through performace reviews. These are also being reviewed with the intention of developing an AM competencies framework within the company.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	There is the requirement for defined levels of management / technical and AM competencies through Job Descriptions / standard Key competency requirements. These are reviewed six monthly through performance reviews. These are also being reviewed with the intetion of developing an AM competencies framework within the company.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	In addition to the annual AMP disclosure, regular contract meetings are held between Safety, Operations, Maintenance, Planning and Capital delivery managers and the respective contractors.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The AMP describes the key attributes of an asset management system however there are gaps in the overall completeness of that system. An effective architectural overview document would provide this visibility and connectivity.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	Various systems are in place for the management of AM information and data. The primary system is GIS. A business review is currently being carried out for the adoption of a proprietry asset management system such as SAP.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Controls are in place to manage the quality of the data entered into the asset management system. Development and training is being carried out to manage the consitency of the data collected.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	Various systems are in place for the management of AM information and data. The primary systems are GIS and MMS. A business review is currently being carried out for the adoption of a proprietry asset management system such as SAP.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	Asset related risks have been implimented as part of the risk management framework. There are however gaps surrounding the risks associated with each stage of the lifecycle of assets.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	The outputs from the risk management process are included for the requirement to control the risk. Work is ongoing to develop a long term resource strategy based on the asset management forecast which is derived from asset knowlege, risk management and future work programmes.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	There is a formal mechanism for ensuring we are meeting our reporting obligations. Senior Policy Analyst at Powercor formally checks with the responsible person whether they are on track for meeting the requirements that are due.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	There are AM policies, procedures and processes in place which deal with the management of assets during the design to commissioning phase. There are procedures to determine how these are derived and prioritised within the asset management plan.There are gaps covering projects accelerated and not inlcuded within the AMP, together with works management quality monitoring. These gaps are being addressed.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	There is a good general; inspection plan in place with remedial actions derived around proritisation of critical defects. Further work is being carried out in standardising the level of consistency across the the inspection and condition assessment proces and how the results are then optimised within the maintenance planning function. These plans are reviewed and optimised on an annual basis.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	A detailed inspection plan is in place with identified and remediated defects reported to the SMT on a monthly basis. Although the majority of measures are reactive in application, leading asset condition and performance measure indicators have been introduced and are driving changes in performance management. Gaps in data and data quality exist however this is being addressed through a proactive review audit review process.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Audits are taken on major faults and asset related failures over a selected threshold value. All asset related failures, Incidents and Near misses are reproted and logged through a defined process with trending carried out on failures, incidents, near misses and defects. Corrective actions are managed through a weekly review and action process.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Company Name	Wellington Electricity
AMP Planning Period	1 April 2013 – 31 March 2023
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	Wellington Electricity
AMP Planning Period	1 April 2013 – 31 March 2023
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Whilst the audit program is mature and targeted to areas of risk and quality delivery, there are some areas of the asset management system and process which are not covered within the current audit regieme		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Incidents and root cause analysis investigations and corrective actions are logged, reviewed and discussed at a weekly Network Management Team meeting.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	Continual improvement and optimisation of asset health, costs and risks across the whole asset lifecycle are in place although need to be finalised and fully implimented and embedded. Continuous improvement processes are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Being part of a wider international group, WE* does place a high level of importance on learnings that can be made from sister companiues within the group and from within the industry in New Zealand. Interatction with AM practitioners outside of the electricity sector is limited.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Company Name	Wellington Electricity
AMP Planning Period	1 April 2013 – 31 March 2023
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The difference represents annual inflation of 2.25% per year. The inflation rate is obtained from the Reserve Bank website for the September Quarter 2012 and sits within the Reserve Bank's target range for inflation.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

The difference represents annual inflation of 2.25% per year. The inflation rate is obtained from the Reserve Bank website for the September Quarter 2012 and sits within the Reserve Bank's target range for inflation.

Appendix B Asset Management Plan Assumptions

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Demand growth	Growth at higher levels may bring forward network reinforcement investment, or conversely a decrease in demand growth may lead to deferral of reinforcement investment	Demand growth will continue to be lower than the national average and will remain steady through the forecast period with an annual growth of electricity consumption and demand between 0.5% and 1.0% in some areas, but showing signs of a slight decline or remaining steady across the network as a whole.	Measured system loadings and load analysis indicate minor load growth in some areas but declining across the network as a whole. No identified major developments. Low to moderate levels of growth in the housing sector. Assumptions supported by NZIER reports.
Capital Expenditure - Customer Driven	Investment levels may increase or decrease in response to changes in demand for new connections from customers	The capital expenditure proposed for customer initiated projects will remain within forecast levels	Overall customer market in residential sector is slow and steady. Minor levels of commercial development. Ability to recover upstream costs for larger investments or uneconomic supplies.
Capital Expenditure - Network Driven	Investment levels may increase or decrease in response to changes in known asset condition and possible increased requirements for asset replacement that cannot be accommodated in present plans, or catastrophic plant failure requiring a high one-off cost	The capital expenditure proposed for asset integrity and performance will continue at forecast levels, which assume a steady operating state.	The overall condition and rate of aging of network assets is steady and no "step change" in expenditure is expected.
Operational Expenditure - Routine Inspection and Maintenance	Any material change to the annual maintenance programme may lead to an increase, or decrease in the OPEX costs associated with inspection and maintenance.	The inspection and maintenance expenditure proposed will remain within forecast levels for the next 3 years. Although aging network assets, routine of inspection and servicing is not likely to change.	Field Services Agreement outlines maintenance programme for duration of the contract

Operational Expenditure - Reactive Maintenance	A change in the rate of failure of network equipment could lead to an increase in reactive maintenance requirements and costs. A change to the field service provider could lead to a higher cost of maintenance.	The reactive maintenance expenditure proposed will remain within forecast levels for the next 3 years. Aging assets may lead to higher levels of reactive maintenance required longer term.	Field Services Agreement is expected to continue. No apparent change in rate of failure of equipment.
Inflation	Capital and Operational Expenditure forecasts have been inflated for future years to take into account changes in CPI, the cost of labour and materials. Should inflation vary from the assumed value then forecast amounts may increase or decrease.	The inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b are: • All balances reflect increases in costs due to an annual forecast inflation rate of 2.25% obtained from the Reserve Bank website for the September Quarter 2012; and • Labour costs are forecast to increase by CPI plus 1% and materials expenses by CPI plus 0.75%.	Based upon current market information.
Quality targets	Any increase in quality targets, or alteration in the assessment method, may lead to increased level of investment to improve network performance.	The quality targets for the Wellington Electricity business in the period 2010 – 2015 will be maintained as per the Commerce Commission's decision paper on the default price path, November 2009.	Quality targets are regulated and won't change until 2015. After 2015 changes may occur, especially with consultation and consumer desire for a more reliable system, with corresponding increase in return on investments to provide resilience and reliability.

Regulatory environment	A change to the regulatory environment may lead to increased or decreased ability to recover on investments. Investment levels will be adjusted to maintain regulatory compliance and to achieve a sustainable return on investments	Spending to meet regulated quality levels is factored into forecast expenditures. Whilst the regulatory environment will continue to encourage Wellington Electricity to invest in the network to meet the quality targets, the current uncertainty with starting prices under the default price path and the regulatory framework, means there is a risk that regulatory change will impact on total investment levels in the future. Specifically if prices are reduced there will be less funds available to invest in operating and capital expenditures under a default price path.	Quality targets are set for a five year period with the next review due in 2015.
Transmission Network	A change to the configuration or capability of the transmission system could lead to a requirements for increased levels of investment on the network to provide capacity or security in the absence of grid capability	The transmission grid, and grid exit point connections will remain unchanged apart from agreed projects.	Asset Plans from Transpower indicate no significant changes to the grid within the planning period. Ownership boundaries may change in time with review of customer connection assets by Transpower, and desire by lines companies to purchase and operate these assets.
Transmission Pricing	Changes to the methods of transmission pass-through pricing may lead to increased expenditure as grid alternative options become more attractive in a non pass-through environment	The transmission pricing methodologies will remain largely unchanged and the transmission pass-through pricing will remain in place.	Transmission pricing is regulated as a pass-through cost and our expectation that this will remain as a pass-through cost with the net effect to the business remaining the same.
Shareholders	Changes to the regulatory environment and the allowed regulated return on investment impact on shareholders and may lead to either increased or reduced expenditure.	Shareholders will continue to be incentivised to invest in the network to allow the business to achieve market returns because the Commerce Commission has provided a fair starting price outcome under the default price path, which will not negatively impact on forecast expenditures.	Starting price provided by the Commerce Commission has not had a negative impact on the ability to provide a recovery for the investment made by the business

Economy	An increase in the cost of raw materials and imported equipment could cause an increase in investment costs, or lead to deferral of projects to remain within budgets.	The commodity markets will remain stable during the forecast period limiting equipment price rises. GDP growth in the area supplied by Wellington Electricity will continue to be lower than the national average, and is likely to be modest at best for the foreseeable future. Industrial and large commercial activity continues to decline.	Present economy is depressed, but global prices appear stable based on recent trends. Strong NZ dollar allows for steady materials costs. Apparent growth on the network and observation of local business activities supports this assumption.
Business cycle	The evolution of a business and its operating environment can impact on strategic decision making and overall approach.	Whilst more mature assets require a higher level of maintenance there is no evidence to suggest that asset conditions will cause a material change to the asset management plan. This remains subject to further consultation with stakeholders and the Commerce Commission around large events which impact on business continuity and further strategic assessments of network resilience plans.	Until discussions with stakeholders and the Commerce Commission clarify impacts and expectations around resilience and business continuity plans, it is appropriate to continue to plan for a steady state business cycle.
Technology	Increased levels of network reinforcement may be required to accommodate sudden load increases at consumer premises resulting from demand side technologies, or significantly reduced loads may be seen that could defer investment if load reduction technologies are introduced to consumers	There will be no dramatic changes that would result in a rapid uptake of new technology by consumers leading to higher expenditure or stranding of existing network assets.	At demand side, displacement or disruptive technologies such as electric vehicles, vehicle-to-grid and distributed generation are still costly and unlikely to have high uptake. The areas of "smart" technology are not commercially viable over the period unless a return on their investment is built into the present DPP by the regulator
Public Safety	Assets in the public domain may require higher than average rates of replacement, or increased level of isolation from the public leading to higher costs, or reallocation of work programmes	That compliance with requirements for public safety management will not adversely impact upon the existing network assets located in the public domain	Implementation of a public safety management system in the business, including compliance with NZS7901 and promoting a culture of incident reporting and safety awareness.

Appendix C Summary of AMP Coverage of Information Disclosure Requirements

Information Disclosure Requirements 2012 clause	AMP section
3.1 A summary that provides a brief overview of the contents and highlights information that the **EDB** considers significant	2.1
3.2 Details of the background and objectives of the **EDB**'s asset management and planning processes	2.4
3.3 A purpose statement which- 3.3.1 makes clear the purpose and status of the **AMP** in the **EDB**'s asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes 3.3.2 states the corporate mission or vision as it relates to asset management 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB** 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management 3.3.5 includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans	2.2 2.4 2.4 2.4 2.4
3.4 Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed	2.5
3.5 The date that it was approved by the **directors**	2.5
3.6 A description of stakeholder interests (owners, **consumers** etc) which identifies important stakeholders and indicates- 3.6.1 how the interests of stakeholders are identified 3.6.2 what these interests are 3.6.3 how these interests are accommodated in asset management practices 3.6.4 how conflicting interests are managed	2.6

Information Disclosure Requirements 2012 clause	AMP section
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including- 3.7.1 governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors** 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured 3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	2.7.1 2.7.2 2.7.5
3.8 All significant assumptions: 3.8.1 quantified where possible 3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including 3.8.3 a description of changes proposed where the information is not based on the **EDB**'s existing business 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information 3.8.5 the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	1.3 and Appendix B
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	Appendix B
3.10 An overview of asset management strategy and delivery	2.9 and 2.10
3.11 An overview of systems and information management data	2.8
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	2.8.5
3.13 A description of the processes used within the **EDB** for- 3.13.1 managing routine asset inspections and **network** maintenance 3.13.2 planning and implementing **network** development projects 3.13.3 measuring **network** performance.	2.10.1 to 2.10.5

Information Disclosure Requirements 2012 clause	AMP section
3.14 An overview of asset management documentation, controls and review processes	2.11
3.1.5 An overview of communication and participation processes	2.12
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	1.1
3.17 The **AMP** must be structured and presented in a way that the **EDB** considers will support the purposes of **AMP** disclosure set out in clause 2.6.2 of the determination.	N/A
4. The **AMP** must provide details of the assets covered, including- 4.1 a high-level description of the service areas covered by the **EDB** and the degree to which these are interlinked, including- 4.1.1 the region(s) covered 4.1.2 identification of large **consumers** that have a significant impact on network operations or asset management priorities 4.1.3 description of the load characteristics for different parts of the **network** 4.1.4 peak demand and total energy delivered in the previous year, broken down by **sub-network**, if any.	3.1 to 3.2
4.2 a description of the **network** configuration, including- 4.2.1 identifying bulk electricity supply points and any **distributed generation** with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the **subtransmission** system fed from the bulk electricity supply points, including the capacity of **zone substations** and the voltage(s) of the **subtransmission network**(s). The **AMP** must identify the supply security provided at individual **zone substations**, by describing the extent to which each has n-x **subtransmission** security or by providing alternative security class ratings; 4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the **network**'s distribution substation arrangements; 4.2.5 a description of the **low voltage network** including the extent to which it is underground; and 4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	3.3
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	N/A

Information Disclosure Requirements 2012 clause	AMP section
Network assets by category 4.4 The **AMP** must describe the **network** assets by providing the following information for each asset category- 4.4.1 voltage levels; 4.4.2 description and quantity of assets; 4.4.3 age profiles; and 4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	3.4
4.5 The asset categories discussed in subclause 4.4 above should include at least the following- 4.5.1 Sub transmission, 4.5.2 Zone substations 4.5.3 Distribution and LV lines, 4.5.4 Distribution and LV cables 4.5.5 Distribution substations and transformers , 4.5.6 Distribution switchgear 4.5.7 Other system fixed assets, 4.5.8 Other assets; 4.5.9 assets owned by the **EDB** but installed at bulk electricity supply points owned by others; 4.5.10 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.11 other generation plant owned by the **EDB**.	3.4
<u>Service Levels</u> 5. The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	4.1 4.2
6. Performance indicators for which targets have been defined in clause 5 above must include **SAIDI** and **SAIFI** values for the next 5 **disclosure years**.	4.1.1
7. Performance indicators for which targets have been defined in clause 5 above should also include- 7.1 **Consumer** oriented indicators that preferably differentiate between different consumer types; 7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	4.1.2.1 4.1.2.2 4.1.2.3

Information Disclosure Requirements 2012 clause	AMP section
8. The **AMP** must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes **consumer** expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The **AMP** should demonstrate how stakeholder needs were ascertained and translated into service level targets.	4.3
9. Targets should be compared to historic values where available to provide context and scale to the reader.	4.1
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	N/A
Network Development Planning 11. **AMP**s must provide a detailed description of **network** development plans, including— 11.1 A description of the planning criteria and assumptions for **network** development;	5.1
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	5.2
11.3 A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs;	5.6
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss- 11.4.1 the categories of assets and designs that are standardised; 11.4.2 the approach used to identify standard designs.	5.6
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	5.6.3
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the **network**.	5.5
11.7 A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision.	5.2

Information Disclosure Requirements 2012 clause	AMP section
11.8 Details of demand forecasts, the basis on which they are derived, and the specific **network** locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 11.8.2 provide separate forecasts to at least the **zone substation** level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts; 11.8.3 identify any **network** or equipment constraints that may arise due to the anticipated growth in demand during the **AMP planning period**; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of **distributed generation** in a **network**, and the projected impact of any demand management initiatives.	5.7 and 5.9
11.9 Analysis of the significant **network** level development options identified and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; 11.9.3 consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment.	5.8, 5.10, 5.11, 5.12, 5.14
11.10 A description and identification of the **network** development programme including **distributed generation** and non-network solutions and actions to be taken, including associated expenditure projections. The **network** development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**.	5.16
11.11 A description of the **EDB**'s policies on **distributed generation**, including the policies for connecting **distributed generation**. The impact of such generation on network development plans must also be stated.	5.9

Information Disclosure Requirements 2012 clause	AMP section
11.12 A description of the **EDB**’s policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional **network** augmentation. These are typically approaches that would reduce **network** demand and/or improve asset utilisation; and 11.12.2 the potential for non-network solutions to address **network** problems or constraints.	5.10
Lifecycle Asset Management Planning (Maintenance and Renewal) 12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including— 12.1 The key drivers for maintenance planning and assumptions; 12.2 Identification of **routine and corrective maintenance and inspection** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**.	6.1 to 6.3
12.3 Identification of **asset replacement and renewal** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets; 12.3.2 a description of innovations made that have deferred asset replacement; 12.3.3 a description of the projects currently underway or planned for the next 12 months; 12.3.4 a summary of the projects planned for the following four years (where known); and 12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**. 12.4 The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	6.4 and 6.5

Information Disclosure Requirements 2012 clause	AMP section
Non-Network Development, Maintenance and Renewal 13. **AMP**s must provide a summary description of material non-network development, maintenance and renewal plans, including— 13.1 a description of non-network assets; 13.2 development, maintenance and renewal policies that cover them; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	6.7
14. **AMP**s must provide details of risk policies, assessment, and mitigation, including— 14.1 Methods, details and conclusions of risk analysis; 14.2 Strategies used to identify areas of the **network** that are vulnerable to high impact low probability events and a description of the resilience of the **network** and asset management systems to such events;	8
15. AMPs must provide details of performance measurement, evaluation, and improvement, including— 15.1 A review of progress against plan, both physical and financial;	10
15.2 An evaluation and comparison of actual service level performance against targeted performance;	7 and 10
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	10.4
15.4 An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the **AMP** must describe any planned initiatives to address the situation.	10.3
Capability to deliver 16. **AMPs** must describe the processes used by the **EDB** to ensure that- 16.1 The AMP is realistic and the objectives set out in the plan can be achieved; 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.13

Appendix D Glossary of Terms

AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
AMP	Asset Management Plan
CB	Circuit Breaker
CBD	Central Business District
CCT	Covered Conductor Thick
CEO	Chief Executive Officer
CIGRE	Conference Internationale des Grands Reseaux Electriques (International Council for Large Electric Systems)
CKI	Cheung Kong Infrastructure Holdings Limited
Cu	Copper
DC	Direct Current
DGA	Dissolved Gas Analysis
DTS	Distributed Temperature Sensing
EDO	Expulsion Drop-out
FPI	Fault Passage Indicators
GWh	Gigawatt Hour
GIS	Geographical Information System
GXP	Grid Exit Point
HV	High Voltage
ICP	Installation Control Point
IEEE	Institute of Electrical and Electronic Engineers
IISC	International Infrastructure Services Company (NZ Branch)
km	Kilometre
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kW	Kilowatt

LV	Low Voltage
LVABC	Low Voltage Aerial Bundled Conductor
MW	Megawatt
MVA	Mega Volt Ampere
NICAD	Nickel Cadmium Battery
Nilstat ITP	Protection Relay
ODV	Optimised Deprival Value/Valuation
O&M	Operating and Maintenance
PAHL	Power Asset Holdings Limited
PDC	Polarisation Depolarisation Current
PIAS	Paper Insulated Aluminium Sheath Cable
PILC	Paper Insulated Lead Cable
PLC	Programmable Logic Controller
PVC	Polyvinyl Chloride
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Systems Applications and Processes
SCADA	Supervisory Control and Data Acquisition System
SF_6	Sulphur Hexafluoride
TASA	Tap Changer Activity Signature Analysis
TCA	Transformer Condition Assessment
VRLA	Valve Regulated Lead Acid Battery
W/S	Winter / Summer
XLPE	Cross Linked Polyethylene Cable