wellington electricity™

Wellington Electricity

10 Year Asset Management Plan

1 April 2016 – 31 March 2026

Wellington Electricity

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

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Wellington Electricity Lines Limited (Wellington Electricity) has prepared this Asset Management Plan (AMP) for public disclosure in accordance with the requirements of the Electricity Distribution Information Disclosure Determination, October 2012 (Consolidated in 2015).

Information, outcomes and statements in this version of the AMP are based on information available to Wellington Electricity that was correct at the time of preparation. Some of this information may subsequently prove to be incorrect and some of the assumptions and forecasts made may prove inaccurate. In addition, with the passage of time, or with impacts from future events, circumstances may change and accordingly some of the information, outcomes and statements may need to change.

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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 2016 to 2026. We confirm that this AMP has been prepared in accordance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 requirements.

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. We have again been fortunate this year that the major weather events of the past few years have not continued in 2015. Being free from natural disruptive events has provided a stable operating period where we have met the levels for our customer service targets.

The network continues to perform to expectations based on investment levels. It is pleasing to see that greater engagement has continued to improve performance of third parties working around our assets. Health and safety has been the focus of updating our existing Field Services Agreement for faults and maintenance services as well as reaching agreement with Chorus to attach fibre to designated overhead assets as part of the Government UFB roll-out. However we must never become complacent in this area and regular site visits to engage with field crews is important to build a strong culture and evaluate the continuous improvement in safety behaviours.

We continue to invest in the network assets where they require replacement or maintenance to meet the required asset performance standards so that we can ensure we operate a safe and reliable electricity delivery infrastructure. This requires good planning and evaluation of tactical responses to asset field data which is driven from well-defined asset strategies. This is central to the role delivered by this AMP and how it communicates our business drivers and forward work plans to meet the requirements of our stakeholders.

The economic outlook for the region is moving to a positive sentiment with the housing market heating up and developers' activity also increasing within the region. However this has come from a low base and it is expected that energy consumption will continue to decline before market activity stabilises this trend. The cooler 2015 winter increased peak demand in some network areas but falling energy consumption remains the overall trend.

Sound risk management practices are used to analyse the various business impacts we face and the effectiveness of the controls we have in place to manage our operations effectively. We have almost completed the evaluation of 328 of our buildings and identification of the strengthening investment required. The Government has proposed further change from the initial 15 year timeframe to complete the remedial work and the AMP has redirected expenditure to complete the work within the seven year window however it remains unclear how this additional cost will be funded. Under the 2014 DPP decision, additional resilience expenditure requested by WELL was not included in the allowances set by the Commission, as Wellington Electricity was the only distributor to ask for an increase for resilience expenditure. This is a strategic resilience step towards having key network equipment protected and available to operate following a major earthquake event, to support the community, business and economic recovery for the region. 2016 will see further work with businesses to develop further initiatives.

We continue to strive for improved business efficiency. Changes are in play such as reorganising structures within Wellington Electricity to harmonise our field services work so that less truck rolls occur while completing asset replacement and refurbishment work. We are also completing a refresh of core IT systems as part of version upgrades to SCADA, billing, and maintenance management software, with our GIS platform scheduled for later this year. The website upgrade has also attracted a positive response, especially the live reporting on restoration times when power outages occur. Availability of this customer facing system will be extended by way of a smart phone app in 2016.

This 2016 AMP has allowed Wellington Electricity sufficient time to evaluate and include analysis from the 28 November 2014 regulatory DPP price reset decision. Our 2015 AMP raised concerns from the price reset regarding CPRG forecasting and how this may require some expenditure to be deferred, due to the approach of not representing declining volumes when resetting prices in 2015. It has been reassuring to see comments at the start of the 2016 Input Methodology review that initial thinking is moving towards a Revenue Cap from 2020 which will address issues raised about the risk of error in CPRG forecasting and consequential windfall gains and losses to both suppliers and consumers.

We have also made progress towards adopting clearer price signals to customers through enhanced price tariffs. Wellington Electricity would like to move toward more cost-reflective pricing, and signal periods when the network has capacity for more demand and when it does not. This would be a great fit for enabling new technologies and for customers and networks to drive mutual benefits from new technology investment. This move towards cost reflective tariffs is limited however by regulatory constraints including the Electricity (Low Fixed Tariff Option for Domestic Consumers) Regulations and the weighted average price cap.

The move towards a cost reflective pricing methodology will also assist in changing the current business model and traditional capex investment timing for blocks of capacity (substations). Designing clear cost reflective prices would send signals to customers to reduce peak demand and slow down the traditional network reinforcement timing required to support increasing peak demand periods.

With these developments and further targeted network analysis, Wellington Electricity is comfortable that the expenditure allowances for the current period will meet the investment required in the network to deliver reliable services to customers at a quality which meets the expected regulatory quality targets. Introducing cost reflective pricing over time requires support from regulatory changes as well as further co-ordination with retailers to complete Smart Meter installation and data sharing, plus the need to undertake an education process with consumers on the benefits they receive from aligning behaviour to these price signals.

We will continue to proactively engage with the Commerce Commission and the Electricity Authority on improvements to the Price-Quality path and market regulations. The outcome is for customers to receive the long term benefits from sustainable investments made in electricity infrastructure so services and quality levels are maintained for the price points accepted by customers.

We continue to reduce gaps identified in the output from our Asset Management Maturity Assessment Tool (AMMAT). The implementation project for SAP Plant Maintenance module is complete and further refinements are ongoing as we drive field and planned work efficiencies into planned, remedial and corrective maintenance activities.

Overall Wellington Electricity is managing a mature set of assets which, when not affected by large natural events, are performing well for customers.

We are also proud to continue with positive endorsement from Telarc of the compliance of the operational systems we use to ensure ongoing safety of our assets located in public areas. The Public Safety Management System (NZS 7901) is a standard which assists with supporting our strong focus on continuing to develop an engaged health and safety culture.

Being a member of the CKI and 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 its business strategy, Wellington Electricity will continue to focus on the development of asset management strategies in parallel with the short to long term planning of the network. We look forward to submitting proactively on the 2016 Input Methodology review and support positive changes, such as a revenue cap, which will better enable cost-reflective pricing to further drive efficient infrastructure investment for stakeholders, so we continue 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

Contents

Section 1:
Executive Summary

1 Summary

The purpose of this Asset Management Plan (AMP) is to communicate Wellington Electricity's approach for the safe, effective and responsible long-term management of the company's network assets, and to ensure that electricity supply continues to be delivered at a quality and price sought by electricity consumers connected to the network.

1.1 Term covered by the AMP

This AMP covers the 10-year period commencing 1 April 2016 and finishing on 31 March 2026. It was approved by Wellington Electricity's Board of Directors on 29 March 2016.

1.2 Changes from the 2015 AMP

The 2016 AMP includes updates on key issues identified in the 2015 AMP and has been modified to enhance its readability for interested parties. The key changes in the 2016 AMP are:

- An updated assessment on the impact of the Commerce Commission's (the Commission) November 2014 Default Price-quality Path (DPP) reset decision. The DPP was released just ahead of the 2015 AMP publication and therefore the effects were not included in the 2015 Plan. The 2016 Plan reflects the 2014 DPP reset decision;
- Revisions to forecast capital and operating expenditure following a detailed review of network development plans and corresponding network investment plans; and
- Structural improvements to enhance the readability of the document for interested parties.

The 2015 AMP included a separate section outlining a high level view of concerns from the likely impacts of the DPP reset decision. In addition to some initial observations, it was noted that a full re-evaluation of forecast expenditure would be incorporated into the next AMP. There were key differences between the outcomes from the DPP reset decision compared to the expected outcome assumed in the 2015 AMP. These differences arose from:

- The uncertainty of future revenues caused by a significant gap between the Commission's forecast of energy consumption growth (referred to as constant price revenue growth (CPRG)), applied when setting starting prices in the DPP reset decision, in comparison to Wellington Electricity's observed ongoing decline in energy consumption volumes by consumers; and
- The reduction in Wellington Electricity's allowable capital and operating expenditure set by the Commission for the regulatory period 2015 to 2020, in comparison to the forecast expenditure in the AMP.

The review of investment plans that form the basis of future expenditure requirements on Wellington Electricity's network has now been completed and an updated investment profile has been incorporated into the plans and expenditure forecasts presented in this AMP.

This AMP demonstrates that Wellington Electricity is forecasting capital and operating expenditure to ensure it continues to provide the quality of service required by consumers. These forecasts are driven by asset health and network development strategies, and are within the expenditure allowances set. The forecasts within this AMP are based on the key assumptions outlined in Appendix A.

Wellington Electricity's investment prioritisation process will enable projects that reduce the likely negative impact on quality to be identified and prioritised accordingly. Each of the critical assumptions is covered in more detail in the sections below.

Wellington Electricity strongly supports the Commission's review of Input Methodologies in 2016 and the emerging views of the Commission around the form of price control published on 29 February 2016 as part of this review. In particular, the emerging view that a pure revenue cap should be applied as the form of control. Wellington Electricity considers that this will substantially alleviate the issue of revenue uncertainty caused by significant variances between forecast CPRG and actual CPRG, from 2020 onwards.

1.2.1 Trend in Energy Consumption

There remains a substantial difference between the actual and forecast energy consumption on Wellington Electricity's network and the Commission's DPP decision forecast for the five year period ending in 2020. The Commission assumed an average increase in CPRG of 0.45% per annum over the five years from 2015 to 2020. In contrast, since 2011 energy consumption[1] in Wellington has declined at an average rate of 1.1% per annum which has led to an average decrease of 1.46% per annum in CPRG over the same period. This is expected to continue to decline and then stabilise at some point in the planning period. The difference between the Commission's forecast and Wellington Electricity's expected outcomes would result in a projected revenue shortfall of $22M over the five year period[2]. While this is less than the initial projected short fall of $43 million estimated in the 2015 AMP, it is still significant.

Wellington Electricity's energy consumption forecast is based on managing a winter peaking network with a continuation of current consumption trends. The actual consumption on the network will be driven by the actual temperature variations across the seasons, the uptake and application of consumer technology (such as LED lighting, Photovoltaic[3] (PV), battery cells, and electric vehicles (EVs)) and the timing of the one-off consumer led developments. Changes in consumption will also depend on clearer price signals being provided in our lines charge tariffs to encourage consumers to make appropriate economic choices. This is in line with the Electricity Authority's (the Authority) concerns about consumers not having clearer choices on the economics of new technology investments.

With the uncertainty associated with the key drivers of consumption, the revenue received to support the proposed investments and operational costs set out in this AMP may vary from that forecast. The emerging view by the Commission of a change to a revenue cap form of control from 2020, together with the gradual changes Wellington Electricity intends to make in tariff pricing over time (to make it clearer to consumers the economics of new technology choices and consumption behaviour), should effectively address the concerns Wellington Electricity has raised on this matter.

1.2.2 Review of Investment Plans

While energy consumption on the network has declined, peak demand continues to grow within certain localised areas in the network. The signalled developments within the Wellington CBD, and the forecasted

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[1] Energy consumption is a key component of the CPRG.

[2] Based on forecast energy consumption decline of -1% in 2016, -0.5% in 2017 and then 0% thereafter.

[3] PV cells are the same as Solar Cells typically installed on the roof of buildings.

peak demand growth in the Northwestern Area of the network created the need for Wellington Electricity to embark on a review of its integrated network development strategy in late 2014 and early 2015. The 2015 AMP identified that this review was in progress and that the forecast expenditure requirements would be updated following its completion. Accordingly, the 2015 AMP expenditure forecasts were expected to change. The review of the network investment plans and requirements for these areas is now completed and has been incorporated into the expenditure forecasts and plans outlined in this AMP.

As a result of the review, the forecast capital investment requirements have been reduced through refinement and optimisation of the investment options required to maintain network security and quality over the planning period, resulting in more cost effective solutions. The review also identified alternative solutions that remove the need to invest in additional large zone substations and/or extend out the timing for when such investment is required. Specifically:

- The 2015 AMP recommended a new zone substation in the CBD requiring a large "lumpy" capital expenditure. As a result of the review, the development plan now focuses on augmentation of existing 33kV subtransmission assets supplying the CBD;
- The proposed Pauatahanui zone substation has been deferred by two years due to the continuing lower than forecast growth rates in the Northwestern Area than prior plans forecast; and
- The proposed Grenada zone substation remains a strategic option for the long term. However the immediate need will be addressed in the short term by further augmentation of the existing Johnsonville and Ngauranga 33kV networks.

The review has resulted in a lower short term investment profile relative to the proposed solutions in the 2015 AMP and this provides a period to further evaluate new technology solutions rather than the traditional network investment of building new substation assets. With the change in tariff methodology to adopt cost reflective pricing where price periods signal more clearly peak demand reduction, new technology investments are more likely to augment the network ahead of the traditional new substation investments. The main differences between the 2015 AMP and the plan included in this AMP are shown in Figure 1-1, with reductions from 2015 to 2016 shown as positive.

Figure 1-1 Differences between the 2015 and 2016 AMP Capital Investment Plan

The evolution of technology supported by different pricing plans and business models will incentivise consumer behaviour and technology choices which will drive efficient network investment. Therefore the investment profile in future years will continue to change as forecasts are updated. The changing technology environment is discussed further in Section 1.3.2.

The overall updated investment profile for the period through to 2020 is consistent with the expenditure allowances included in the 2014 DPP reset decision. As noted in Section 1.2, these updated forecasts are dependent on current assumptions and expected peak demand profiles projected over the regulatory period ending in 2020. Further information on this is available in Section 7.

When considering peak demand from a network wide perspective; it is important to note that while step changes in peak demand occur at specific sites within the network, this is offset by declining peak demand in other parts. Hence the overall peak demand across the network is expected to increase by less than 2% for the 10 year AMP planning horizon.

Figure 1-2 illustrates the forecast peak demand (system maximum demand) for the last four years and the forecast for the next 10 years.

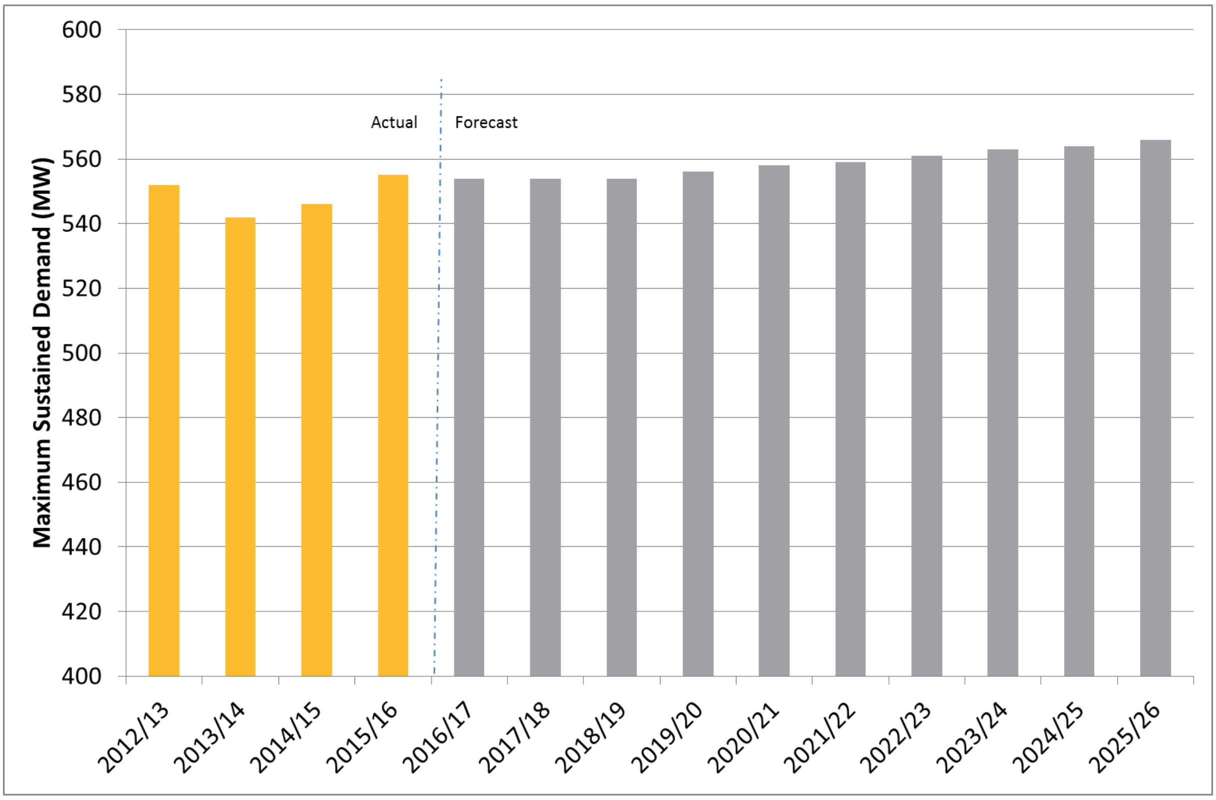


Figure 1-2 Network Historic and Forecast Demand

1.2.3 Changes to the Format of this AMP

To support communication of Wellington Electricity's asset management activities, the presentation of this AMP has been structured into two parts. The first part describes an overview of Wellington Electricity and the approach taken to asset management, while the second presents the 10-year investment plan for asset life cycle management, network development and asset management support systems. The new format is described in more detail in Section 2.

1.3 The Changing Environment

The environment in which Wellington Electricity operates is changing. In particular, this includes changes to health and safety legislation and the rate of change in emerging technology. These changes will increasingly impact on Wellington Electricity's operations going forward and require revision of its current business models.

1.3.1 Health and Safety at Work Act 2015 (HSW Act 2015)

The HSW Act 2015 introduces significant reform in workplace health and safety. These changes include the ongoing requirement for due diligence and governance from Board level down and across all parties involved in the supply continuum. Wellington Electricity is actively reviewing processes to ensure the systems and operating standards reflect the new requirements.

1.3.2 The Technology Environment

Wellington Electricity actively monitors evolving technology trends and the current uptake of new technology that is or will likely impact on the electricity sector. This includes monitoring the uptake of PVs, the increasing penetration of EVs in New Zealand's vehicle fleet, and the applicability and use of technology for network monitoring, design and operation. Additionally, as new technology is incorporated into network equipment, these capabilities are actively considered for use in development plans and asset renewals. For example, Wellington Electricity has leased EV's for its pool vehicle fleet and is also trialling the use of automatic switching within the network.

While the rate of uptake is uncertain, technology is and will continue to have an increasingly significant impact on consumption behaviour with such things as EVs, PVs, and battery storage when it becomes more affordable. While the current uptake of EVs is small, the availability of affordable EVs has the potential to significantly alter electricity delivery and usage patterns. It is expected that the adoption rate of EVs in New Zealand will increase over the longer term based on:

- New Zealand's high level of renewable energy generation (over 80%) being an ideal match for EVs which will be seen as an appealing option for environmentally and cost conscious consumers;
- Constantly evolving energy storage systems, electric drives and charging technologies will improve the efficiency and range of EVs; and
- EVs offering lower running costs than traditional internal combustion engines due to the higher cost of fossil fuels and the higher efficiency of energy conversion from battery storage.

There is similar uptake of distributed PV generation by consumers with an associated impact on energy and demand usage on the network. Currently the uptake in Wellington is low compared with other regions but further increases in connections will likely drive investment going forward. To ensure consumers make informed choices around new technology, Wellington Electricity will alter pricing tariffs to encourage the correct adoption that supports the network. For example, in overseas situations, PV is built on feed-in tariff support to reduce day time peaks and reduce thermal generation. This is quite different to New Zealand's renewable energy portfolio and Wellington Electricity's evening peak, which occurs when the sun has gone down. Hence the Wellington network is likely to focus on low cost off peak charging of EVs rather than support solar PV. This is likely to continue until battery storage becomes affordable for consumers enabling a reduction in network peaks.

The fast changing nature of these types of technologies creates uncertainty in the investment requirements going forward. This impacts on the need for additional investment in such things as network control, communications and voltage management, while delivering savings through the more efficient utilisation of current assets. Over the medium term how this evolution in technology will impact on specific projects and the investment plan is unknown, however, it is likely that technology will drive change and new opportunities for lines companies relative to what is available today.

1.4 Resilience

Following changes to the Building Code post the Christchurch earthquakes, a number of Wellington Electricity's pre-1976 substation buildings require reinforcement to ensure they comply with the minimum building standards. The forecast includes an estimated expenditure of $7 million over the planning period, to ensure substations can remain available to support response and recovery following a major natural event. This includes the proposed change initiated by the Government in 2015 to zone earthquake risk areas, and requires high risk areas to remediate buildings through seismic strengthening within a seven year period rather than the original fifteen years.

Under the 2014 DPP decision, additional resilience expenditure requested by Wellington Electricity was not included in the allowances set by the Commission, as Wellington Electricity was the only distributor to ask for an increase for resilience expenditure. As a result, the current programme of substation building reinforcement has been included in the plan as a prolonged programme, limiting the investment made in any one year due to competing needs for allowance expenditure, whilst keeping within the remediation timeframes required by legislation.

During 2016 Wellington Electricity will further develop a business case assessing options to improve the overall resiliency of the network for High Impact Low Probability (HILP) events (such as a major earthquake). This work will involve consultation with key customers as well as other utilities supplying the Wellington region, recognising the interdependencies between electricity supply and other infrastructure providers such as water and roading. This plan will also consider the additional costs of procuring hardware for setting up emergency corridors. Undertaking all this work would require funding above the 2015-20 DPP allowances.

1.5 Service Levels

Within this context Wellington Electricity continues to deliver service levels to consumers and other stakeholders within the region at one of the highest levels in the country. In accordance with Wellington Electricity's mission and stakeholder feedback, four areas of service level measures have been established for the period covered by the AMP. These are:

- Safety Performance;
- Network Performance;
- Asset Performance; and
- Customer Experience.

The measures and targets adopted in each area are described below.

1.5.1 Safety Performance

Wellington Electricity has continued to build on its strong foundation, set by past health and safety performance. Continual improvement in managing health and safety is core to Wellington Electricity and involves ongoing review of health and safety practices, systems and documentation.

Wellington Electricity welcomes the change in Work Safe New Zealand legislation as an ongoing approach to continuing improvement to workplace safety and focus on effective identification and management risk to protect the welfare of workers engaged in delivering our services.

Within this context of continuous improvement, four primary measures have been adopted:

- Lost Time Injury frequency (LTIFR);
- Total Notifiable Event Frequency Rate (TNEFR);
- Incident and near miss reporting; and
- Corrective actions closed.

Planning Period Targets and Initiatives

Wellington Electricity's targets for the 10-year planning period are to:

- Achieve a zero LTI and LTIFR over the whole period;
- Report on at least 500 near misses per annum;
- Reduce the safety related corrective actions to below 50 per annum; and
- Reduce the quality related corrective actions required to below 100 per annum.

1.5.2 Network Performance

Wellington Electricity's network reliability performance (quality) targets from 2016 to 2026 are shown in Figure 1-3. These are the same targets as set by the Commission's 2014 Default Price-Quality Path determination for the 2015 to 2020 regulatory period. These customer focusing targets are based on the average historical performance levels and are among the best in New Zealand. For the purposes of this AMP Wellington Electricity assumes that the current targets will remain in place for the 2021-2026 period.

	Target	Limit[4]
SAIDI[5]	35.44	40.63
SAIFI[6]	0.547	0.625

Figure 1-3 Network Reliability Performance Targets 2016 to 2026

The data set used to establish these performance targets is based on the 10 years from 2004 to 2014 (the reference period). The first five years of the reference period experienced benign weather relative to the last five years. Consequently, the targets represent a performance level that is better than what would be expected given recent weather trends. However, this is partially offset by the lower boundary value used for the Major Event Day threshold (TMED) which acknowledges future storm activity contributes a lower impact on actual values compared to target.

Wellington Electricity's recent performance against 2016-2020 targets are shown in Figure 1-4 and Figure 1-5. To provide a comparison, historical SAIDI and SAIFI figures have been updated to be consistent with the improved measurement approach for dealing with large one-off events, as determined by the Commission for the 2015–2020 regulatory period. There is a small margin between the quality target and the actual limit, and therefore a large one-off event, such as a major storm, can have a significant impact on reliability figures. For example, the multi-day storm that occurred in 2013/14, described as a 1 in 40-year event, had a significant impact on the quality performance in 2013/14 as illustrated in the charts below.

[4] Level where the Commerce Commission may initiate a quality review
[5] System Average Interruption Duration Index
[6] System Average Interruption Frequency Index

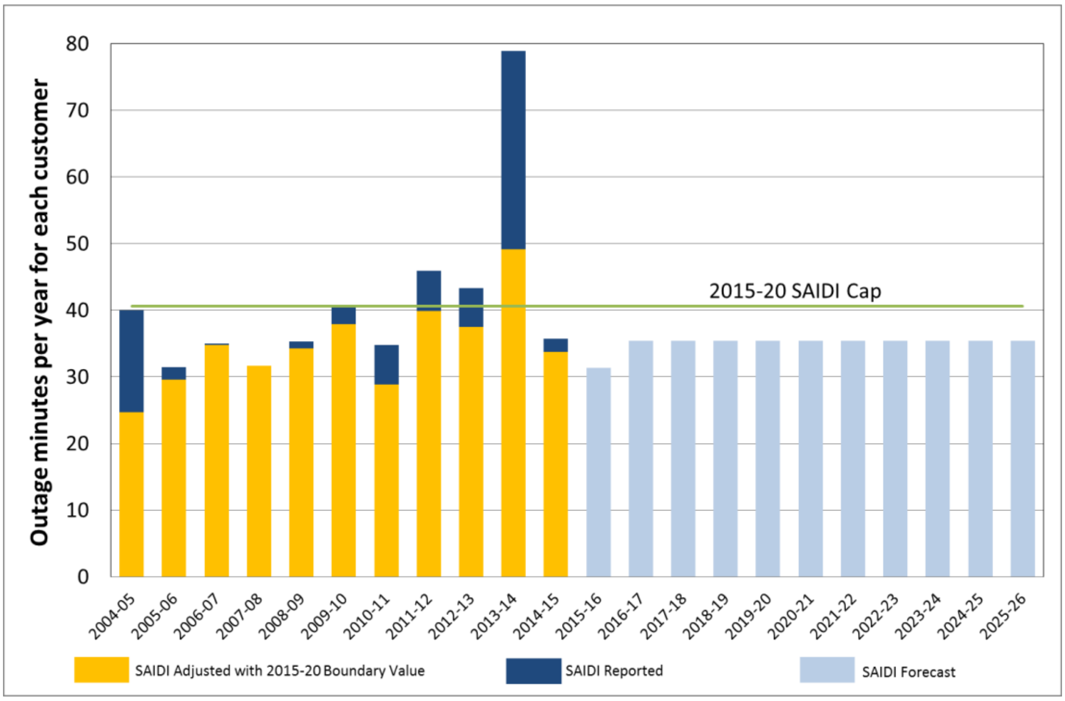


Figure 1-4 Wellington Electricity SAIDI Performance

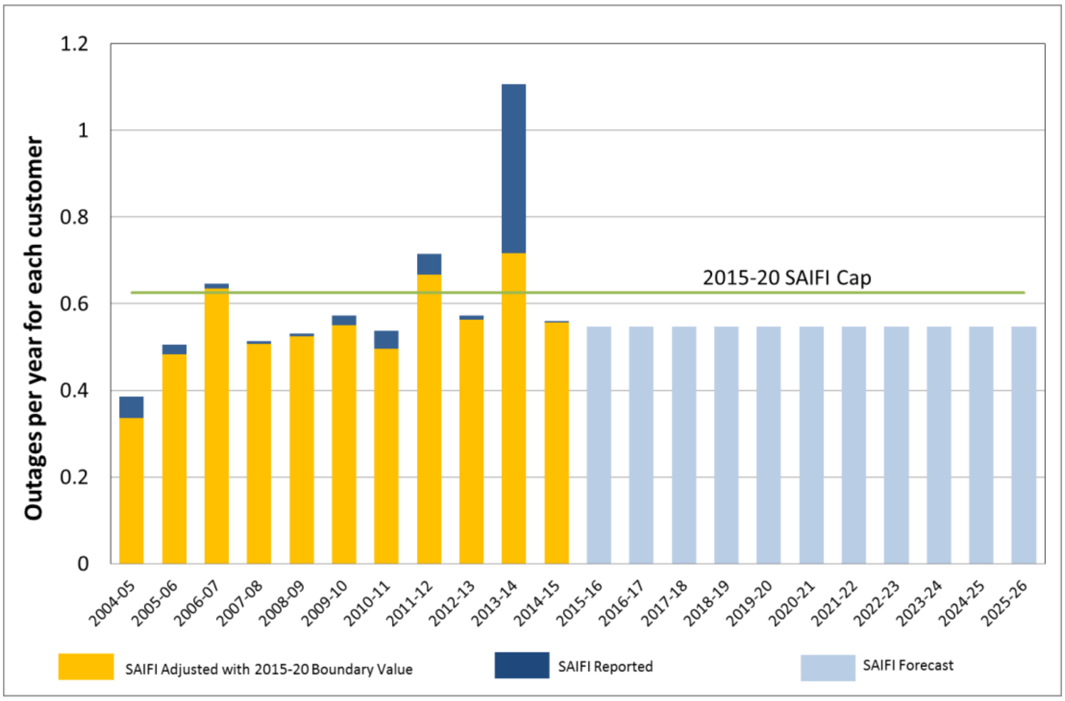


Figure 1-5 Wellington Electricity SAIFI Performance

While Wellington Electricity exceeded the quality limits from 2011/12 to 2013/14 due to the extraordinary weather related events, both the SAIDI and SAIFI reliability limits were within DPP quality standards for the 2014/15 year and are forecast to again be within limits for the 2015/16 year.

Reliability Initiatives

Managing safety and reliability are at the core of Wellington Electricity's continuous improvement process. Key components of this process include:

- Mitigating, where practical, the impact of severe storms by using line sectionalisers and reclosers and by employing well-practiced emergency restoration plans;
- In-depth analysis of all outages (over 0.45 SAIDI minutes) to identify root causes and recommendations to prevent recurrence;
- Monitoring trends in outage causes and other asset failures to identify changes in maintenance practices and/or to confirm assets to be upgraded;
- Monitoring of field response and repair times for major faults to identify causes of prolonged outages and develop strategies to improve restoration times;
- Refinement of the targets to reflect consumer segments;
- Extending risk based analysis to cover conductors and underground cables; and
- Further analysis of wind speed and wind direction forecasting.

1.5.3 Asset Performance

The asset performance targets used by Wellington Electricity relate to the efficiency with which the company 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 measures used are load factor, distribution transformer capacity utilisation, and loss ratio.

Figure 1-6 illustrates the targeted level of performance for each measure over the planning period together with key measures of network density.

	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[7]	61.7	30.7	5.9	39.2	187.7	12.2	16,306
Performance	51.2	40.1	4.2	116.0	499.4	35.4	14,118
Targets 2016-2026	>50%	>40%	<5%	-	-	-	-

Figure 1-6 Wellington Electricity Asset Performance Targets to 2026

1.5.4 Customer Experience

Wellington Electricity has two customer related performance measures. These are:

- Power restoration service level targets; and

[7] Values as of 2015, Source: PWC Compendium

- Contact Centre performance.

Power Restoration Service Level Targets

Wellington Electricity's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to three different categories of consumers: CBD/Industrial, Urban and Rural. These service levels reflect previous feedback from our consumers and are agreed between Wellington Electricity and all retailers. They provide Wellington Electricity with financial incentives to not exceed the maximum restoration times, provided that safety is not compromised.

The targets for power restoration service levels remain consistent over the planning period 2016-2026 and are shown in Figure 1-7.

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

Figure 1-7 Standard Power Restoration Service Level Targets 2016-2026

Contact Centre Performance

Wellington Electricity has developed a set of key performance indicators (KPIs) that provide service level benchmarks for the Contact Centre (Telnet). The nine reported service level performance measures for the Contact Centre are summarised in Figure 1-8.

	Service Element	Measure	Target 2016 to 2026
A1	Overall service level	Average service level across all categories	>80%
A2	Call response	Average wait time across all categories	<20 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	<4%
B1	Initial Outage Notification	Energy retailers notified and the WELL website updated within the time threshold	<5 minutes
B2	Ongoing Outage Updates	Regular outage status updates provided	every 30 minutes
B3	Estimated Time of Restoration (ETR) Accuracy	Accurate ETR provided within the time threshold from initial outage notification	<1.5 hours
B4	Ongoing ETR Updates	Regular status updates to prolonged outages provided within the time threshold	within 2 hours

	Service Element	Measure	Target 2016 to 2026
B5	Restoration Notification	Energy retailers notified and the WELL website updated within the time threshold from the time of restoration	<5 minutes
C1	Specific Contact Centre experience	Wellington Electricity is properly represented during specific calls	Qualitative assessment 80%

Figure 1-8 Contact Centre Service Level Targets 2016-2026

1.6 Network Expenditure

The projected expenditure over the planning period is presented below. Expenditure projections are presented in constant 2016 dollars.

1.6.1 Network Capital Expenditure

Wellington Electricity separates network capital expenditure forecast into four categories:

- Asset Renewal - includes specific replacement projects identified in the fleet summaries and routine replacements that arise from condition assessment programmes. This is the largest component of the forecast and is driven largely by the replacement of high quantity assets such as poles, switchgear and 11kV/400V substations;
- System Growth - is driven by system development needs and is more uncertain due to the dependency on the timing and location of peak demand growth;
- Relocation Capital – expenditure required to relocate assets primarily due to roading projects and where the cost is normally shared with NZTA;
- Customer Connection – includes the costs to deliver customer requested capital projects, such as new subdivisions, customer substations or connections.

The network capital expenditure forecast is shown in Figure 1-9.

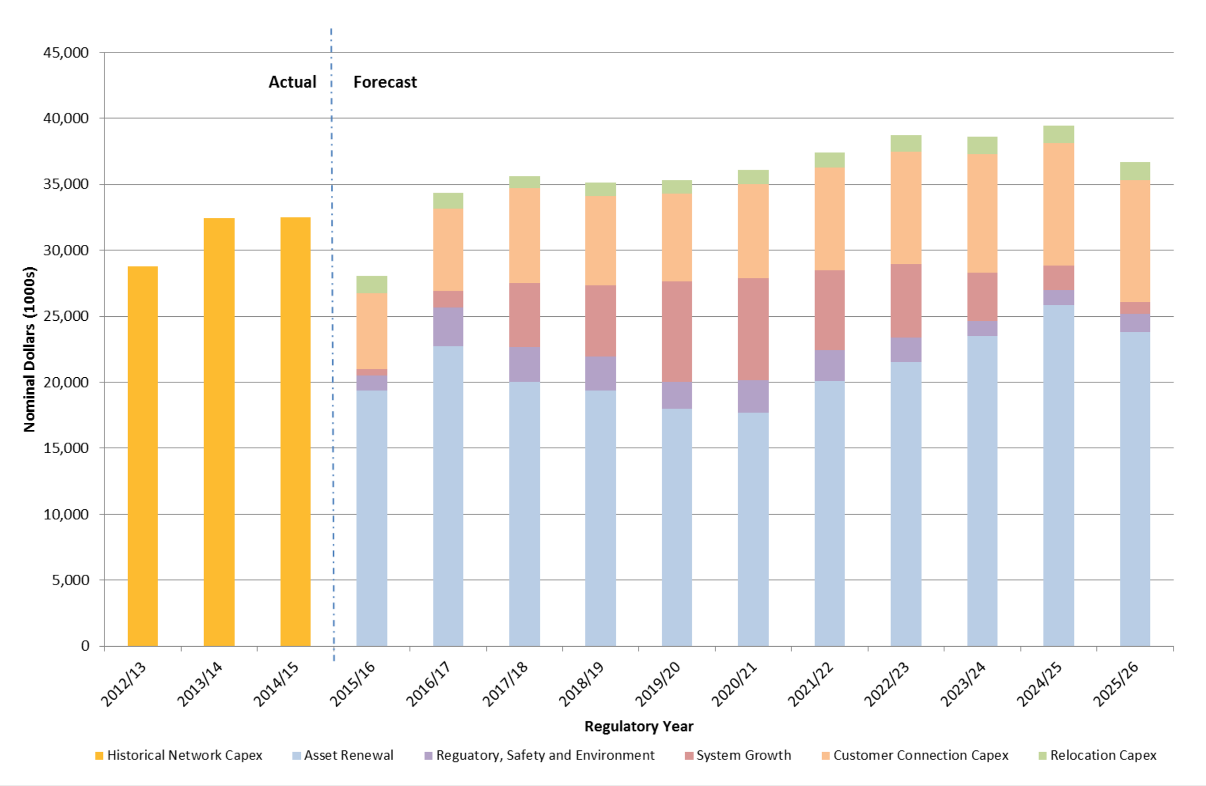


Figure 1-9 Network Capital Expenditure Forecast

The variability of the forecast capital expenditure is driven mainly by System Growth projects required to accommodate localised peak demand growth (as discussed in Section 1.2.2) and variability in the larger 33kV cable replacement projects in the Asset Renewal category.

1.6.2 Network Operational Expenditure

Wellington Electricity separates network operational expenditure forecast into four categories:

- Service Interruptions and Emergency's – includes work that is undertaken in response to faults or third party incidents and includes equipment repairs following failure or damage.
- Vegetation Management – covers planned and reactive vegetation work.
- Routine and corrective maintenance and inspection. This comprises:
  - Preventative Maintenance works – includes routine inspections and maintenance, condition assessment and servicing work undertaken on the network. The results of planned inspections, and maintenance, drive corrective maintenance or renewal activities;
  - Corrective Maintenance works - includes work undertaken in response to defects raised from the planned inspection and maintenance activities; and
  - Value Added - covers customer services such as cable mark outs, stand over provisions for third party contractors, and provision of asset plans for the 'B4U Dig' programme, to prevent third party damage to underground assets.
- Asset Replacement and Renewal - includes repairs and replacements that do not meet the requirements for capitalisation.

The network operational expenditure forecast is shown in Figure 1-10.

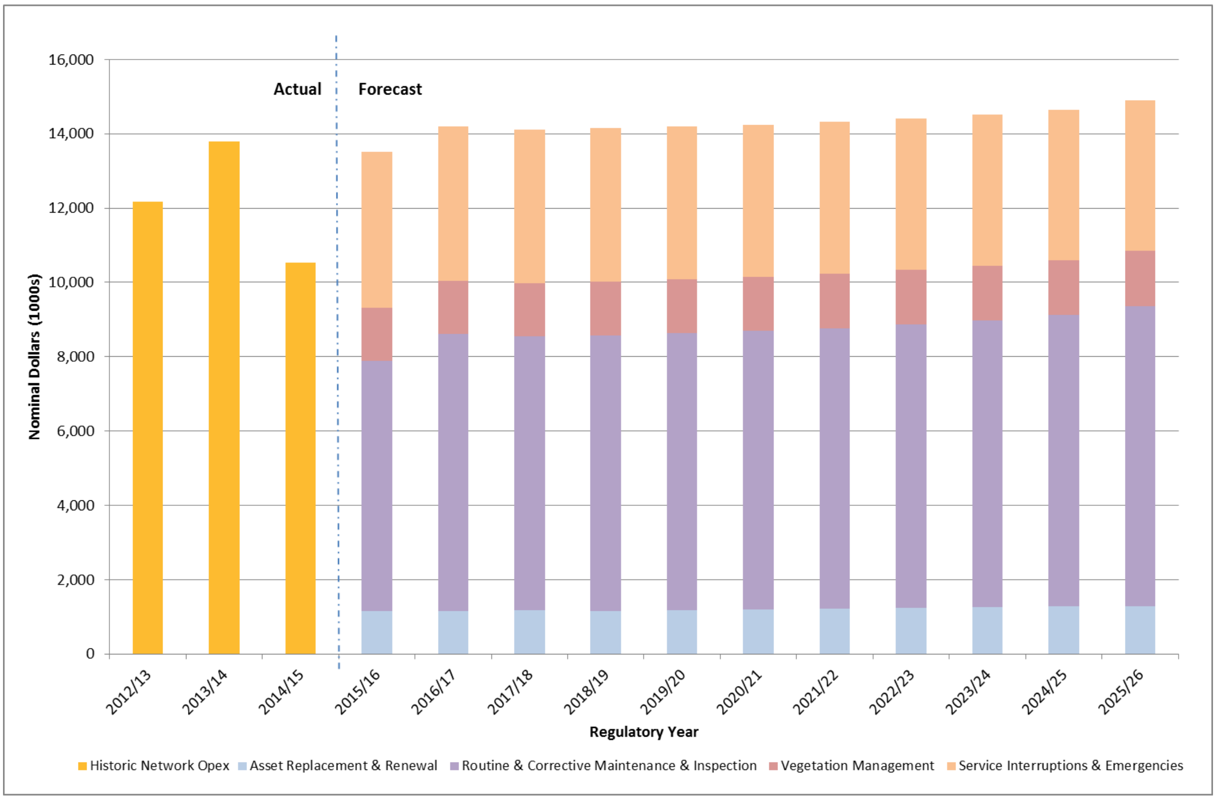


Figure 1-10 Network Operational Expenditure Forecast

1.7 Capability to Deliver

Wellington Electricity has the organisational and external service provider structures in place required to implement this AMP. Where new business requirements exist beyond current practice, these will be assessed against the present business capability and, where necessary, further resources will be considered (whether financial, technical, or contractor resource) to achieve any new business requirements.

As Wellington Electricity is part of the Cheung Kong group of companies it has access to relevant skills and experience from across the world. This provides Wellington Electricity with direct access to international best practice systems.

Wellington Electricity's Board of Directors and senior management team have reviewed this AMP against the business strategy to ensure alignment with business capability and priorities.

Section 2:
Introduction

2 Introduction

This Asset Management Plan (AMP) has been prepared in accordance with the Commerce Commission's (the Commission) Information Disclosure (ID) Determination, October 2012 (consolidated in 2015). It describes Wellington Electricity's long-term investment plans for the planning period from 1 April 2016 to 31 March 2026.

The document was approved for disclosure by the Wellington Electricity Board of Directors on 29 March 2016.

2.1 Purpose of the AMP

The purpose of this AMP is to:

- Be the primary document for communicating with stakeholders Wellington Electricity's asset management practices and planning processes;

- Describe how stakeholder interests are considered and integrated into business planning processes to achieve an optimum balance between the levels of service, price / quality positions, and cost effective investment; and

- Illustrate the interaction between this AMP, Wellington Electricity's mission "*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"*, and its asset management objective to *"optimise the whole of life costs and the performance of the distribution assets to deliver a safe, cost effective, high quality service".*

The asset management practices and this AMP inform Wellington Electricity's business planning processes including its annual Business Plan and Budget.

2.2 Structure of this Document

This AMP has been structured to allow stakeholders and other interested parties to understand Wellington Electricity's business and the operational environment. The body of the AMP is structured into the following two categories:

- **Overview and Approach** which provides an overview of Wellington Electricity, its services levels, and the approach taken to asset management: and

- **10 Year Investment Plan** which describes Wellington Electricity's assets, associated strategies and investment profile over the planning period to meet the defined service levels.

Figure 2-1 illustrates the structure of this AMP.

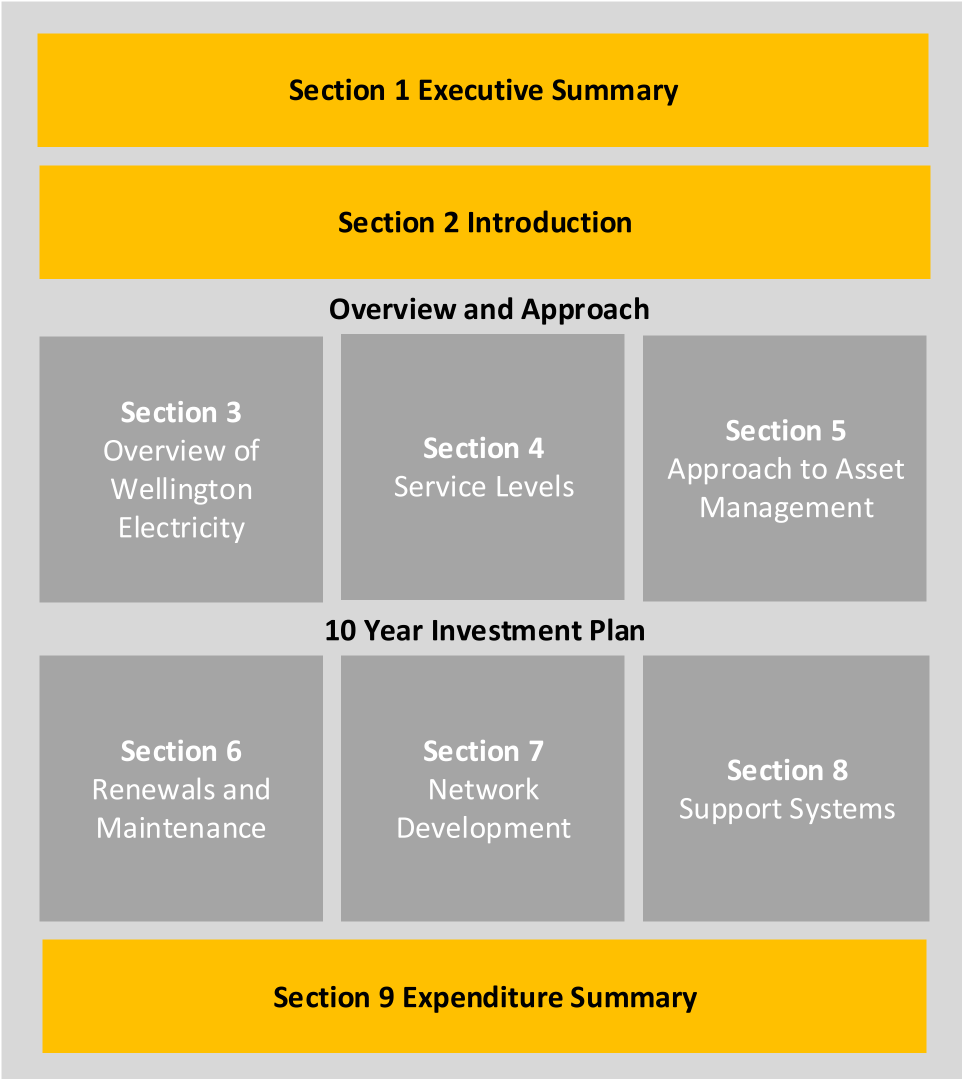


Figure 2-1 Structure of 2016 AMP

2.3 Formats used in this AMP

The following formats are adopted in this AMP:

- Calendar years are referenced as the year e.g. 2016. Wellington Electricity's planning and financial years are aligned with the calendar year;
- Regulatory years are from 1 April to 31 March and are referenced as 20xx/xx e.g. 2016/17;
- All asset data expressed in figures, tables, and graphs is at 30 September 2015 unless otherwise stated;
- ICP numbers are as at 1 April 2015; and
- All asset quantities or lengths are quoted at the operating voltage rather than at the design voltage. For example, Wellington Electricity has a number of 33kV cables operating at 11kV. The length of these cables is incorporated into the statistics for the 11kV cable lengths and not the 33kV cables.

2.4 Investment Projections

The investment described in this AMP underpins Wellington Electricity's current business plan. The expenditure and projects are continually reviewed as new information is incorporated and asset management practices are further refined and optimised. The development of asset management strategies are driven by:

- The need to provide a safe environment for staff, contractors and the public;
- The current understanding of the condition of the network assets and risk management;
- Assessment of load growth and network constraints;
- New and emerging technologies;
- Changes to business strategy driven by internal and external factors; and
- The impact of the regulatory regime.

Accordingly, investment projections within the next two to three years are relatively firm with plans towards the later part of the 10-year period subject to an increasing level of uncertainty.

As described above, Wellington Electricity's financial year and planning cycle are in calendar years. Therefore, project timings in this AMP are expressed in calendar years. However, consistent with information disclosure requirements, expenditure forecasts are based on the regulatory reporting period 1 April to 31 March. Financial values presented in this AMP are in constant price 2016 New Zealand dollars, except where otherwise stated.

Section 3:

Overview of Wellington Electricity

3 Overview of Wellington Electricity

This section provides an overview of the Wellington Electricity business, its mission, corporate structure, governance, accountabilities for asset management, the area supplied and a description of the network. It also describes Wellington Electricity's stakeholders and the changes that are occurring within the wider operating environment that will impact on investment decisions over the short to medium term.

3.1 Mission and Business Plan

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."**

The mission sets the context for all strategic and business planning. Business planning encompasses the asset management planning and delivery. To achieve this mission Wellington Electricity's business and asset management practices and policies must:

- Provide a safe environment for staff, contractors and the public;
- Deliver high quality outcomes for consumers, accounting for the cost/quality trade-off; and
- Operate in the most commercially efficient manner possible within the current regulatory environment.

The mission and these core principles are reflected in Wellington Electricity's Business Plan. The Business Plan is shaped by both the internal and external business environment and defines the company's actions and outcomes to meet its mission.

This AMP is aligned with Wellington Electricity's network development plans and forecasts, and is used to inform its 2016 Business Plan. It also takes into account the interests of consumers, stakeholders, and the changing operating environment (as discussed further in Section 3.7). Figure 3-1 illustrates this flow from Wellington Electricity's mission to the business plan to the AMP.

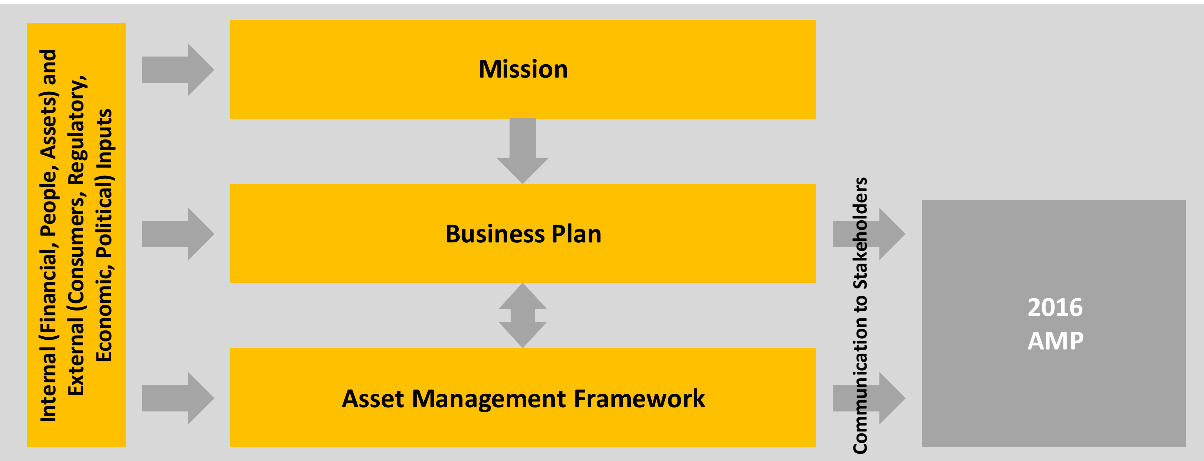


Figure 3-1 Interrelationship between Wellington Electricity's Mission, the Business Plan, the Asset Management Framework and the AMP

The Asset Management Framework utilised by Wellington Electricity is discussed further in Section 5.

3.2 Organisational Structure

3.2.1 Ownership

Cheung Kong Infrastructure Holdings Limited (CKI) and Power Assets Holdings Limited (Power Assets) together own 100 per cent of Wellington Electricity. Both shareholding companies are members of the Cheung Kong group of companies, which are listed on the Hong Kong Stock Exchange (HKEx).

Further information is available on Wellington Electricity's website, www.welectricity.co.nz.

3.2.2 Corporate Governance

The Wellington Electricity Board of Directors (the Board) is responsible for the overall governance of the business. Consolidated business reporting is provided to the Board bi-monthly which includes health and safety reports, capital and operational expenditure against budget, and reliability statistics against targets.

The Board reviews and approves each AMP as well as annual forecasts and budgets.

3.2.3 Financial Oversight, Capital Expenditure Evaluation and Review

Wellington Electricity has a Delegated Financial Authorities (DFA) framework, authorised by the Board, which shows the specific approval limits for the various levels of staff within the business.

Major Project Financial Approval and Governance

The policies for Authorisation and Payment of Project Expenditure together with the Individual DFA, define the procedure for authorisation of Wellington Electricity's capital expenditure.

No expenditure associated with capital projects above $400,000 proceeds until the Capital Investment Committee (CIC), a subcommittee of the Board, has reviewed the project business case and approved the expenditure.

The scope of the CIC is to approve capital expenditure proposals and to ensure that both an appropriate level of diligence has been undertaken and that the investment is in line with Wellington Electricity's strategic direction. The CIC can approve projects previously included in the budget or customer connection projects up to $2 million, otherwise the CIC process refers their review for Board approval.

3.2.4 Executive and Company Organisation Structure

The business activities are overseen by the CEO of Wellington Electricity. The operation of Wellington Electricity's business activities involves three groups of companies, Wellington Electricity, International Infrastructure Services Company (IISC), and other Service Providers that contract to Wellington Electricity.

IISC is a separate infrastructure services company, part of the CKI and Power Assets group, which provides business support services to Wellington Electricity. IISC provides the in-house asset management and planning functions and management of service delivery functions.

Safety is supported by the Quality, Safety and Environment (QSE) team, reporting directly to the CEO. This ensures that safety and risk management remain a prime focus and play a central role in all of Wellington Electricity's activities.

Wellington Electricity operates an outsource model for its field services and contact centre operations. These external service providers are contracted directly with Wellington Electricity, with day to day management of the outsourced contracts provided by IISC. The overall company organisation structure is shown in Figure 3-2.

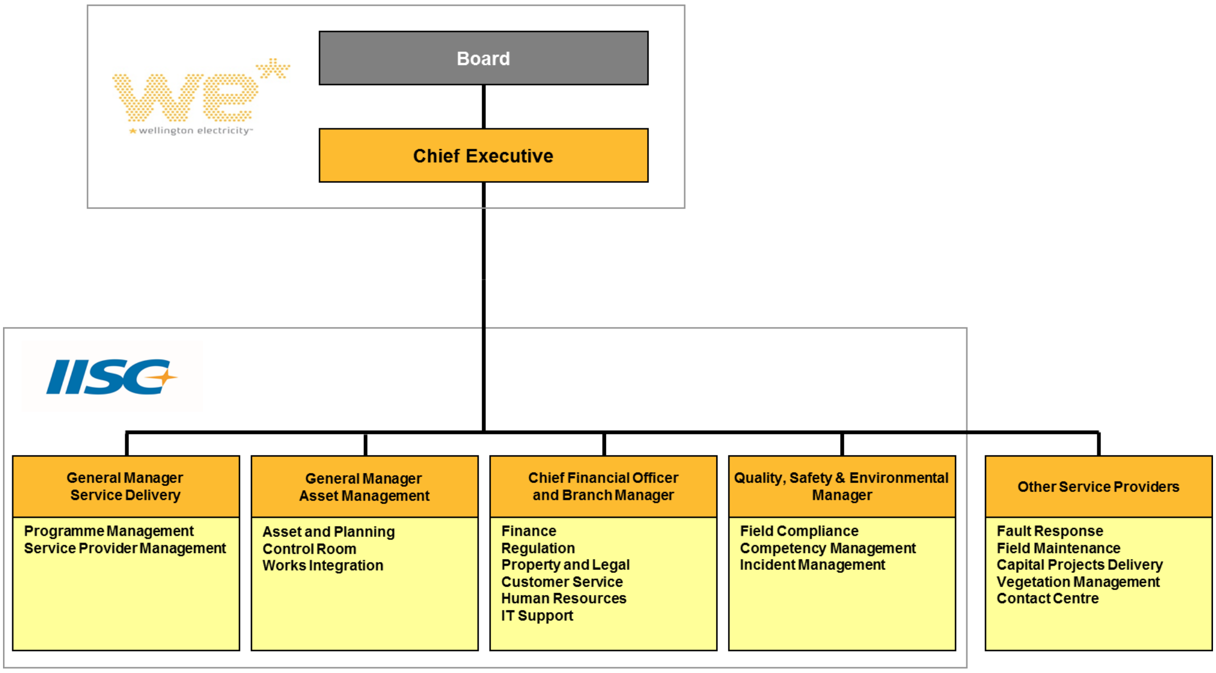


Figure 3-2 Wellington Electricity Organisation Structure

3.2.5 Asset Management Accountability

The Wellington Electricity CEO heads the Executive Management team to implement the company mission. The CEO is accountable to the Board for overall business performance and direction.

In 2015 the General Manager Networks and Operations role was restructured into two roles: the General Manager – Asset Management and General Manager – Service Delivery. The accountabilities for these positions are:

- General Manager – Asset Management is accountable for asset planning, standards, project approvals, works prioritisation and integration and networks operations. Responsibilities also include the management and introduction of new technology onto the network.
- General Manager – Service Delivery is accountable for delivery and project management of capital and maintenance works and the associated safety, quality and environmental performance of these works. Responsibilities also include the management of outsourced field services contracts.

The Chief Financial Officer continues to be accountable for all indirect business support functions including finance, customer service, regulatory management, legal and property management, and human resources and information technology support.

Wellington Electricity's staff and its external service providers' personnel are competent to implement this AMP, with appropriate training programmes in place to ensure that competencies and capability remain current with good industry practice.

3.2.5.1 Asset Management Team

The asset management team responsibilities are separated into three areas: asset and planning, network operations and works integration. The responsibilities for each area are described in Figure 3-3.

Asset Management Teams	Asset Management Responsibilities
Asset and Planning	• Strategic asset and network management • Condition based risk management • Approval of asset management projects, plans, and budgets • Quality performance management • Network policies and standards • Introduction of new technology onto the network
Control Room	• Network operations and safety • Outage management • Fault response and management
Works Integration	• Development, prioritisation, and budget allocation of the 3-12 month combined capex and opex work plan • Analysis of asset data to inform decision making • Wellington Electricity's thought leadership on core asset management applications

Figure 3-3 Asset Management Team Responsibilities

3.2.5.2 Service Delivery

The service delivery team responsibilities are separated into two areas: management of delivery of capital and maintenance works on the network, and management of the specialist contracts. The responsibilities for each area are described in Figure 3-4.

Service Delivery Team	Asset Management Responsibilities
Capital Works and Maintenance programme management	• Overview of the capital works plan and maintenance delivery • Programme management of field service activities • Project management of contestable works Safety frameworks for project implementation

Service Delivery Team	Asset Management Responsibilities
Contract Management	• Management of specialist contracts – Field Services Agreement, Vegetation Management, Chorus agreement, • Safety performance and corrective actions. • Relationship management with stakeholders

Figure 3-4 Service Delivery Responsibilities

Wellington Electricity outsources the majority of its field services tasks as well as its contact centre. Management of the field service provider contracts is the responsibility of the General Manager – Service Delivery. Management of the contact centre falls with the Chief Financial Officer's responsibilities.

The outsourced field operations and approved Wellington Electricity service providers are summarised below, along with their contractual responsibilities:

- 24x7 fault dispatch and response, maintenance, capital works – Northpower;
- Contestable capital works – Northpower, Downer and Connetics;
- Vegetation management – Treescape; and
- Contact centre – Telnet.

The contracts with our outsourced service providers are structured to ensure alignment with Wellington Electricity's asset management objectives and to support continuous improvement in the integrity of the asset data held in Wellington Electricity's information systems.

The roles and service provided by the service providers are explained in further detail Section 5, Asset Management Approach.

Contractor working on an underground cable

3.3 Distribution Area

Wellington Electricity is an electricity distribution business (EDB) that supplies electricity to approximately 166,000 consumers in its network area, represented by the yellow-shaded area in Figure 3-5. The area encompasses the Wellington Central Business District (CBD), the large urban residential areas of Wellington City, Porirua, Lower Hutt and Upper Hutt, interspersed with pockets of commercial and light industrial load, and the surrounding rural areas. The area does not have any large industrial and agricultural loads.

Each local authority in the area (Wellington, Porirua, Hutt and Upper Hutt Councils) has different requirements relating to permitted activities for an electrical utility. For example, differences exist in relation to road corridor access and environmental compliance. In addition to the local authorities, the entire network area comes under the wider control of the Wellington Regional Council.

Prior to deregulation, network development in the region was the responsibility of two separate organisations and consequently in many cases the equipment utilised and the network design standards differ between the two historic network areas.

As illustrated in Figure 3-5 the network has been split into three areas for planning purposes: Southern, defined as the area supplied by Wilton, Central Park and Kaiwharawhara grid exit points (GXPs); Northwestern, defined as the area supplied by Takapu Road and Pauatahanui GXPs; and Northeastern, defined as the area supplied by Upper Hutt, Haywards, Melling and Gracefield GXPs. The network configuration for each of the three areas is described further in Section 3.4.

Figure 3-5 Wellington Electricity Network Area

3.4 The Network

The total system length of Wellington Electricity's network (including streetlight circuits but excluding traction direct current (DC) cable) is 6,595km, 61.3% of which is underground. The network is supplied from Transpower's national transmission grid through nine grid exit points (GXPs). Central Park, Haywards and Melling GXPs supply the network at both 33kV and 11kV, and Kaiwharawhara supplies at 11kV only. The remaining GXPs (Gracefield, Pauatahanui, Takapu Rd, Upper Hutt and Wilton) all supply the network at 33kV only.

The 33kV subtransmission system distributes the supply from the Transpower GXPs to 27 zone substations at N-1 security level. The 33kV system is radial with each circuit supplying its own dedicated power transformer, with the exception of Tawa and Kenepuru where two circuits from Takapu Road are tee-ed to supply four transformers (two at each substation). All 33kV circuits supplying zone substations in the Southern 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 195km, of which 137km is underground. A single line diagram of the subtransmission network is included in Appendix G.

The 27 zone substations incorporate 52 33/11kV transformers. Each zone substation has a pair of transformers with one supply from each side of a Transpower bus where this is available. The exception to this is Plimmerton and Mana, which each have a single 33kV supply to a single power transformer. However, the substations are connected by an 11kV tie cable and as a result they operate as a single N-1 substation with a geographic separation of 1.5km.

The zone substations in turn supply the 11kV distribution system which distributes electricity directly to the larger consumers and to 4,304 distribution substations located in commercial buildings, industrial sites, kiosks, berm-side and on overhead poles. The total length of the 11kV system is approximately 1,756km, of which 66% is underground. 70% of the 11kV feeders in the Wellington CBD[8] are operated in a closed ring configuration, with the remainder being radial feeders that provide interconnections between neighbouring rings or zone substations.

The majority of consumers are fed from the distribution substations via the low voltage (LV) distribution network. The total LV network length is approximately 2,748km, of which 60% is underground. An additional 1,869km of LV lines and cables are dedicated to providing street lighting services.

The Wellington City trolley bus network is supplied through Wellington Electricity owned direct current (DC) assets. These assets are managed in accordance with a network connection and services agreement with NZ Bus Limited (the sole consumer supplied by these assets), with capital and operational expenditure funded outside of this AMP. The agreement expires in 2017 with an extension option of up to 10 years. Each network area is described in further detail below.

[8] The CBD is defined as the commercial areas supplied by Frederick St, Nairn St, University, The Terrace, Moore St and Kaiwharawhara substations.

3.4.1 Southern Area

The Southern Area network is supplied from the Central Park, Wilton, and Kaiwharawhara GXPs, which together supply Wellington City and the CBD. Figure 3-6 illustrates the Southern Area subtransmission network configuration.

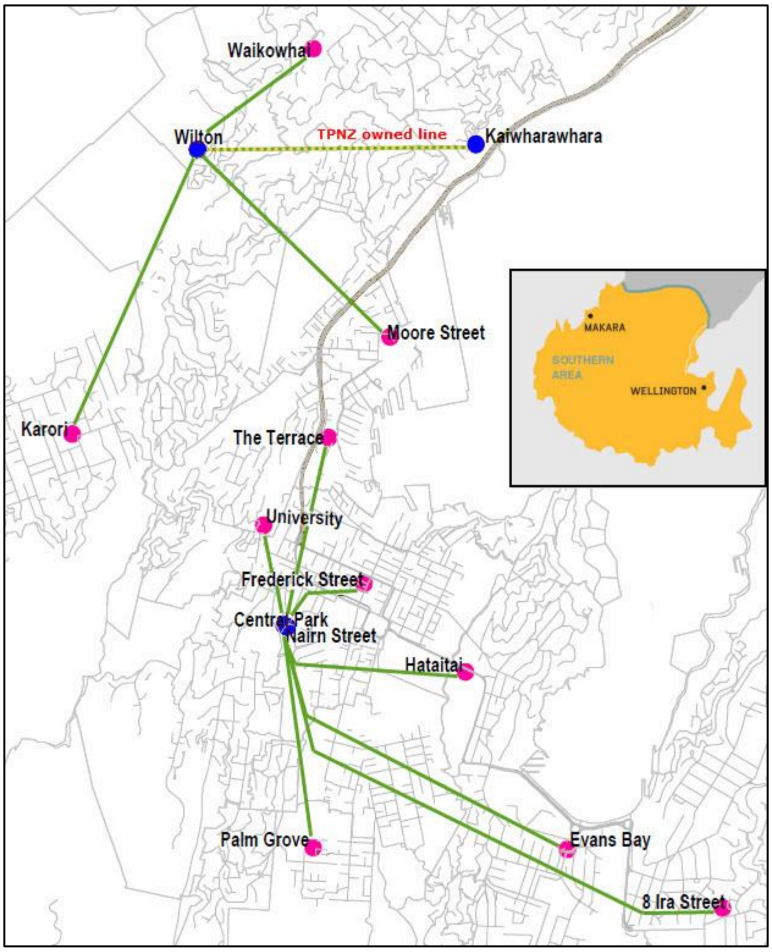


Figure 3-6 Wellington Southern Area Subtransmission Network

Central Park

Transpower's Central Park GXP comprises three 110/33kV transformers - T5 (120MVA), T3 and T4 (100MVA units) - supplying a 33kV bus. There are also two Transpower-owned 33/11kV (25MVA) transformers supplying local service and an 11kV point of supply.

Central Park is supplied at 110kV by three overhead circuits from Wilton GXP. There is no 110kV bus at the GXP, so an outage on one circuit will cause the loss of the transformer connected to that circuit.

Central Park GXP supplies zone substations at Ira Street, Evans Bay, Hataitai, Palm Grove, Frederick Street, University, and The Terrace. Double circuit 33kV underground cables supply each of these substations. Central Park GXP also supplies the Nairn Street switching station at 11kV via two underground duplex 11kV circuits (four cables). The Nairn Street site is adjacent to the Central Park GXP.

Wilton

Transpower's Wilton GXP comprises two 220/33kV transformers operating in parallel, supplying a 33kV bus that feeds zone substations at Karori, Moore Street, and Waikowhai Street through double circuit underground cables. The transformers at Wilton are each nominally rated at 100MVA.

Kaiwharawhara

Kaiwharawhara is supplied by two 110kV circuits from Wilton GXP, and has two 38MVA 110/11kV transformers in service. Wellington Electricity takes 11kV supply from Transpower's Kaiwharawhara GXP and distributes this via a Wellington Electricity owned switchboard located within the GXP.

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

3.4.1.1 Southern Area Summary

Supply Point	Connection Voltage (kV)	Sustained Maximum Demand – 2015 (MVA)	Firm Capacity[9] (MVA)	Energy Injection – 2015 (GWH)	ICP Count
Central Park 33kV	33	156	228	710	44,084
Central Park 11kV	11	23	30	94	5,453
Wilton 33 kV	33	53	106	232	12,264
Kaiwharawhara 11kV	11	34	41	155	5,928
Total				**1,191**	**67,729**

Figure 3-7 Summary of Southern Area GXPs

3.4.2 Northwestern Area

The Northwestern Area network is supplied from the Pauatahanui and Takapu Road GXPs, which supply Porirua City and the Tawa, Johnsonville, and Ngauranga areas of Wellington City. Figure 3-8 illustrates the Northwestern Area GXP and subtransmission network configuration.

[9] Firm Capacity is the n-1 transformer capacity.

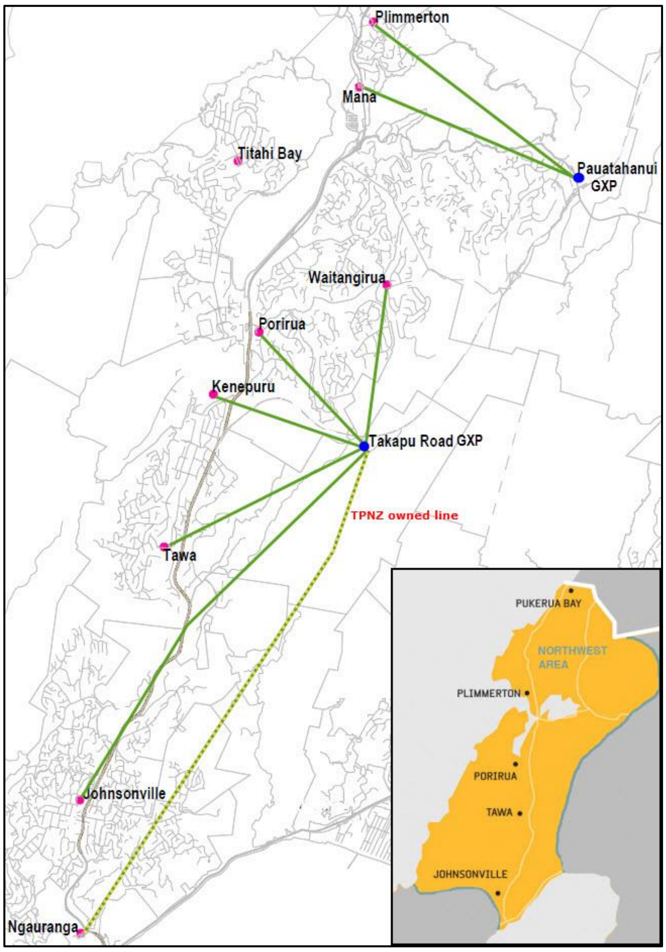


Figure 3-8 Wellington Northwestern Area Subtransmission Network

Pauatahanui

Transpower's Pauatahanui GXP comprises two parallel 110/33kV transformers each nominally rated at 20MVA. Pauatahanui GXP supplies Mana and Plimmerton zone substations via a single 33kV overhead circuit connection to each substation. The two zone substations have a dedicated 11kV interconnection, providing a degree of redundancy when one of the 33kV circuits is out of service.

Takapu Road

Transpower's Takapu Road GXP comprises two parallel 110/33kV transformers nominally rated at 90MVA each. Takapu Road GXP supplies zone substations at Waitangirua, Porirua, Tawa, Kenepuru, Ngauranga and Johnsonville via double 33kV circuits. These circuits leave the GXP as overhead lines across rural land and become underground lines at the urban boundary.

3.4.2.1 Northwestern Summary

Supply Point	Connection Voltage (kV)	Sustained Maximum Demand – 2015 (MVA)	Firm Capacity (MVA)	Energy Injection – 2015 (GWH)	ICP Count
Pauatahanui 33kV	33	20	24	69	6,855
Takapu Rd 33kV	33	93	123	391	30,998
Total				**460**	**37,853**

Figure 3-9 Summary of Northwestern Area GXPs

3.4.3 Northeastern Area

The Northeastern Area network is supplied from the Upper Hutt, Haywards, Melling and Gracefield GXP's, which supply the Hutt Valley and the surrounding hills. Figure 3-10 illustrates the Northeastern Area subtransmission network configuration.

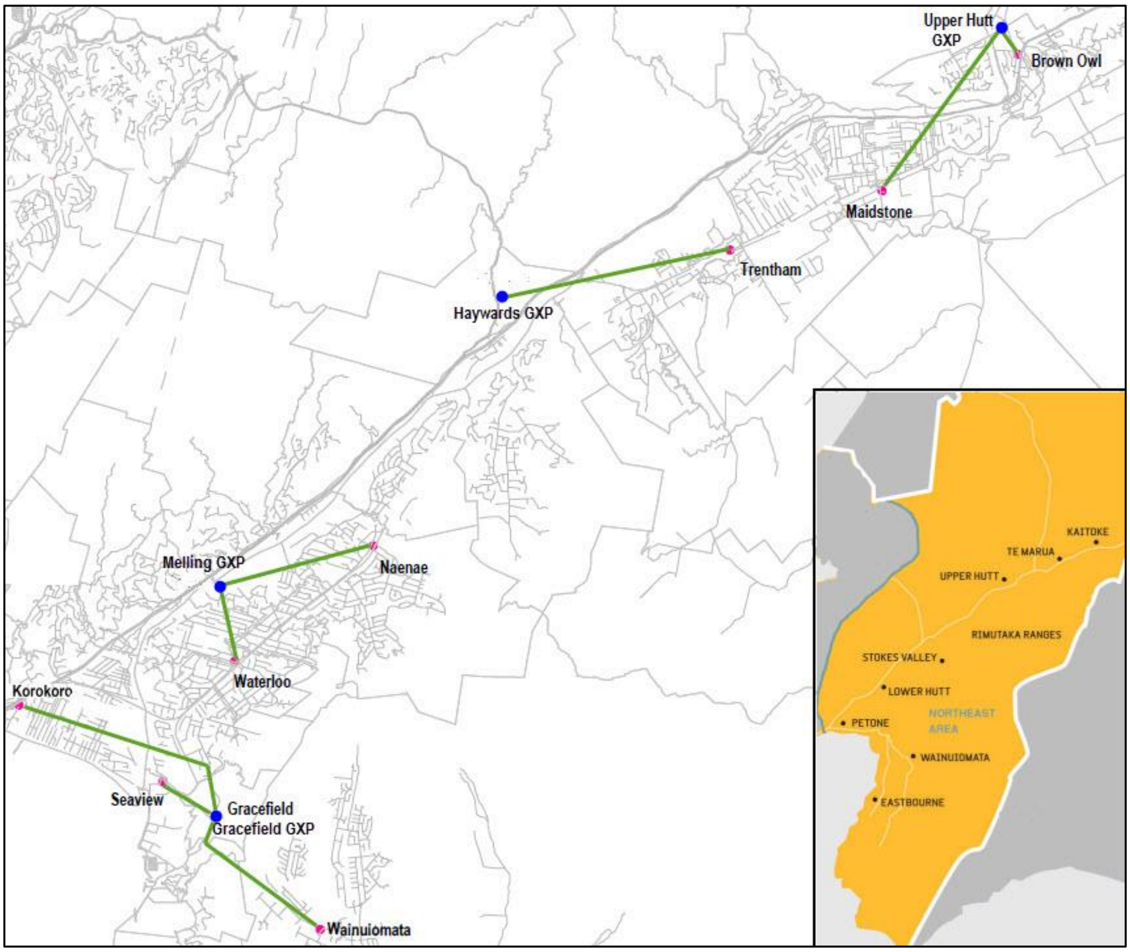


Figure 3-10 Wellington Northeastern Area Subtransmission Network

Upper Hutt

Transpower's Upper Hutt GXP comprises two parallel 110/33kV transformers each nominally rated at 37MVA. Upper Hutt GXP supplies Maidstone and Brown Owl zone substations via double circuit 33kV underground cables.

Haywards

Transpower's Haywards GXP has a single 110/11kV transformer nominally rated at 20MVA feeding an 11kV switchboard and a single 110/33kV transformer nominally rated at 20MVA. A 5MVA 33/11kV transformer links the 33kV and 11kV switchboards. Wellington Electricity takes supply to two 33kV circuits that supply Trentham zone substation, and eight 11kV feeders. Haywards is the only GXP that does not currently offer full N-1 security to Wellington Electricity's connected assets, and discussions are underway with Transpower regarding a solution to this. Security is currently provided by backfeeds in the Wellington Electricity 11kV network.

Melling

Transpower's Melling GXP comprises two parallel 110/33kV transformers each nominally rated at 50MVA which supply zone substations at Waterloo and Naenae via duplicated 33kV underground circuits. Melling also includes an 11kV switchboard fed by two parallel 110/11kV transformers each nominally rated at 25MVA, from which Wellington Electricity takes supply to 10 11kV feeders.

Gracefield

Transpower's Gracefield GXP comprises two parallel 110/33kV transformers nominally rated at 85MVA each. Gracefield GXP supplies Seaview, Korokoro, Gracefield and Wainuiomata zone substations via double 33kV circuits. The line to Wainuiomata is overhead but underground cables supply the other substations. Wellington Electricity's Gracefield zone substation is located on a separate site adjacent to the GXP with short 33kV cable sections connecting the GXP to the zone substation.

3.4.3.1 Northeastern Summary

Supply Point	Connection Voltage (kV)	Sustained Maximum Demand – 2015 (MVA)	Firm Capacity (MVA)	Energy Injection – 2015 (GWH)	ICP Count
Gracefield 33kV	33	62	89	278	19,061
Haywards 33kV	33	15	20	61	5,125
Melling 33kV	33	35	52	139	11,824
Upper Hutt 33kV	33	30	37	128	10,697
Haywards 11kV	11	19	20	67	6,593
Melling 11kV	11	27	27	116	7,134
Total				**789**	**60,434**

Figure 3-11 Summary of Northeastern Area GXPs

3.4.4 Embedded Generation

There is a wide range of embedded generation connected to the network, including over 500 installations of PV solar panels averaging 3.3kW per site. The largest embedded generation site is the 60MW windfarm at Mill Creek, which connects into Wellington Electricity owned 33kV circuits from Wilton. Four customers have significant (>0.5 MW) standby diesel generators. Other embedded generation includes two sites with gas turbines that run on landfill gas, the Brooklyn wind turbine, and small scale hydroelectric generation stations commissioned at some Greater Wellington Regional Council water storage and pumping stations.

A summary of the embedded generation connected to Wellington Electricity's network is in Figure 3-12.

Generation Type	Sites	Installed Capacity (MW)
Known Standby Diesel	Prison	1.62
	Hospitals	10.8
	Others	0.5
	Total	*12.9*
Landfill Gas	Silver Stream	3.0
	Happy Valley	1.2
	Total	*4.2*
Hydroelectric	Various	1.3
Photovoltaic	Various	1.7
Wind	Mill Creek	59.8
	Brooklyn	0.23[10]
	Others	0.02
	Total	*60.0*
Total		**80.2**

Figure 3-12 Summary of Embedded Generation

3.4.5 Embedded Distribution Networks

Within the Wellington Electricity network there are a number of embedded networks owned by others, which are typically apartment buildings, commercial buildings, or campuses such as retirement villages.

Wellington Electricity is not responsible for these networks, and generally provides a metered bulk supply point. The management of the assets within these networks, and the associated service levels, are not the responsibility of Wellington Electricity and are excluded from this AMP.

[10] The Brooklyn wind turbine is currently being upgraded to a 900kW unit.

3.5 Regional Demand and Consumer Mix

In 2015/16 Wellington Electricity's network is forecast to deliver 2,463 GWh to consumers around the region where the regional sustained maximum demand was 555 MW[11]. As illustrated in Figure 3-13, the volume of energy supplied through the network has declined at an average rate of 1.1% per annum from 2011 to 2016. Overall the trend of declining volumes is forecast to continue at least for the next two years.

It should be noted that this trend of decline was reduced in 2015/16 with volumes forecast to increase (0.9%) for the first time since 2011, reflecting a colder winter period.

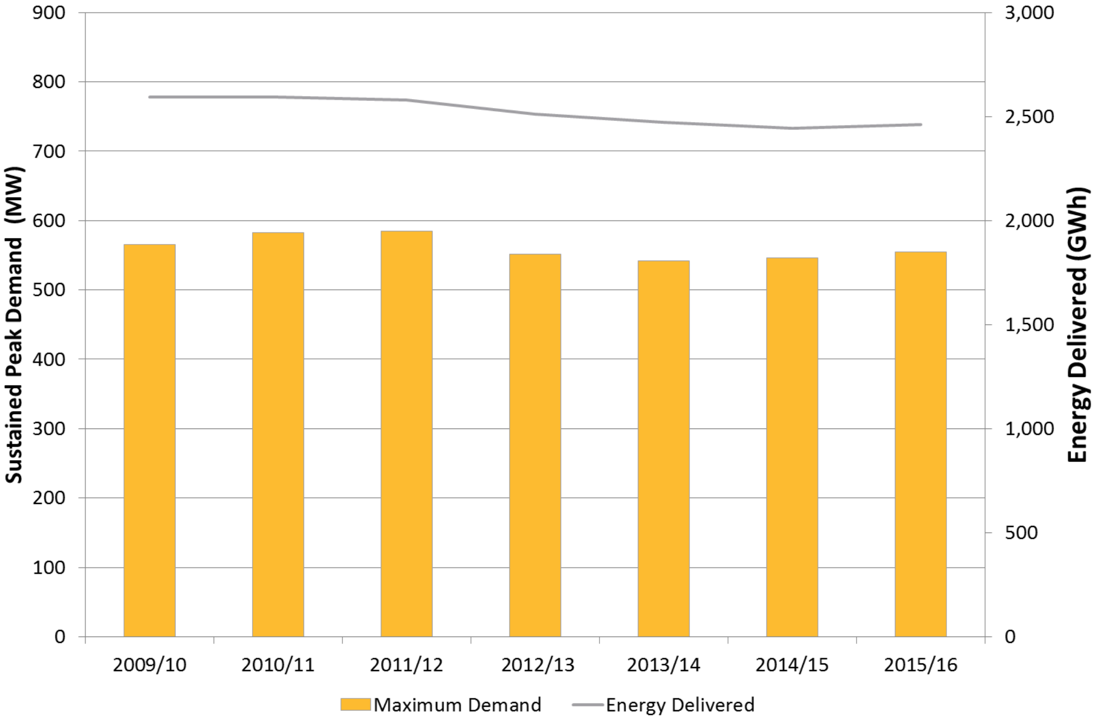


Figure 3-13 Peak Demand and Energy Injected

As set out in Figure 3-14 the overall consumer mix on the Wellington network consists of approximately 90% residential connections.

[11] Winter peak period in 2015/16 has passed

Consumer Type	ICP Count
Domestic	148,648
Large Commercial	382
Medium Commercial	408
Small Commercial	15,356
Large Industrial	39
Small Industrial	500
Unmetered	589
Individual Contracts	16
Total	**165,938**

Figure 3-14 Wellington Electricity's Consumer Mix as at February 2015

While the majority of consumers connected to the network are residential, a number of consumers have significant or strategically-important loads. These include:

- Parliament and government agencies;
- Hospitals, emergency services and civil defence;
- Council infrastructure such as water and wastewater pumping stations and street lighting;
- Major infrastructure providers such as NZTA, Wellington Airport and CentrePort;
- Large education institutions such as Victoria University, Massey University, Whitireia and Weltech;
- Network security sensitive consumers such as the stock exchange, Weta Digital, Datacom, and Department of Corrections; and
- Electrified public transport operators.

The number and density of these consumers is atypical for a New Zealand distribution network. Therefore, the importance of Wellington Electricity providing a reliable and resilient network is critical.

Wellington Electricity's ten largest consumers (by annual consumption) are:

- Wellington City Council
- Hutt City Council
- Chorus
- Porirua City Council
- Foodstuffs
- New Zealand Transport Agency (NZTA)
- Progressive Enterprises
- Capital and Coast District Health Board
- Vodafone NZ
- Weta Digital

Wellington Electricity has a Customer Services Team that meets face-to-face with major consumers at least once a year to discuss and understand their specific needs, the impact of network operations and asset management priorities, and any concerns they may have. Consumers who have significant electricity use, specific electricity requirements, or are suppliers of essential services are contacted prior to planned outages, as well as following any unplanned outages that impact their supply.

Consumers' interests are identified and incorporated into asset management decisions through a number of mechanisms. These are discussed further in Section 3.6.

3.6 Wellington Electricity's Stakeholders

Wellington Electricity has identified eight key stakeholder groups whose interests are considered in the approach taken to asset management and its outcomes for consumers. These stakeholder groups are:

- Consumers;
- Retailers;
- Regulators;
- Transpower;
- Central and local government;
- Industry organisations;
- Staff and contractors; and
- Shareholders.

The characteristics of these groups are described below including how their interests are identified, what their interests and expectations are and how these are accounted for in Wellington Electricity's asset management processes. The resulting service levels sought by stakeholders, once their interests have been accounted for, are described in Section 4.

3.6.1 Stakeholder Groups

3.6.1.1 Consumers

Consumers' interests are identified through direct feedback and media enquiries. Their interests include the safety of the public, the reliability of the network, and the price they pay for that reliability. These interests are accounted for in the asset management practices through meeting the regulated quality targets, public safety and consumer engagement initiatives.

Wellington Electricity is developing a wider Consumer Engagement Programme to further facilitate direct information exchange with consumers. The Wellington Electricity website has been used to socialise safety related messages and provide consumers with network outage information. It will be developed to use a variety of communication channels, including social media, for the exchange of information between Wellington Electricity and consumers.

3.6.1.2 Retailers

Retailers (and directly connected large loads) are Wellington Electricity's direct customers. They rely on the network to deliver energy which they sell to consumers. Retailers ask that Wellington Electricity assists in providing innovative products and services to benefit their customers and they expect to access load control under the Electricity Authority Model Use of System Agreement. In conjunction with retailers, Wellington Electricity is developing protocols to enable third party load control while maintaining public safety, and ensuring distribution and transmission network operational requirements are met.

Customer supply quality interests are accounted for through meeting the quality targets and by achieving the customer service levels contained in Wellington Electricity's Use of System Agreement with retailers. Wellington Electricity is working with the Electricity Authority, and other electricity market participants, in the development of more standardised Use of System Agreements or Default Distribution Agreements (DDA)

Wellington Electricity consults with retailers prior to the implementation of changes to its line charge pricing and tariff structure to ensure that any proposed changes take note of retailer feedback.

3.6.1.3 Regulators

The main regulators for Wellington Electricity are the Commerce Commission (the Commission) and the Electricity Authority (the Authority). Regulators are interested in ensuring that consumers achieve a supply of electricity at a fair price commensurate with an acceptable level of quality that provides long term benefits to consumers. These interests are accounted for in the asset management practices through planned compliance with reliability targets and price controls, compliance with legislation, engagement in regulatory development process and preparing information disclosures.

The regulators' powers are identified through legislation and regulations (such as Part 4 of the Commerce Act 1986, Electricity Industry Act 2010 and the Electricity Industry Participation Code 2010 (EIPC)), industry working groups, information disclosure requirements; and relationship meetings and direct business communications.

3.6.1.4 Transpower

Transpower's interests are identified through the EIPC, relationship meetings, direct business communications, annual planning documents, and grid notifications and warnings. Transpower is primarily interested in sustainable revenue earnings from the allocation of connected and interconnected transmission assets, and require assurance that downstream connected distribution and generation will not unduly affect their assets. They have interests in the operation of national grid including rolling outage plans, automatic under frequency load shedding (AUFLS) and demand side management. These interests are accounted for in Wellington Electricity's asset management practices through implementation of operational standards and procedures; appropriate investment in the network, and regular meetings.

3.6.1.5 Central and Local Government

Central and local government interests are identified through legislation, regulations, regular meetings, direct business communications, and working groups. In addition to being a significant consumer through street lighting, electrified public transport and water management, they are interested in compliance with legislative and regulatory obligations, appropriate lifelines obligations for emergency response and contingency planning to manage a significant civil defence event. These stakeholders want assurance that consumers receive a safe, reliable supply of electricity at a competitive price, no environmental impact from the operation of the network, and appropriate levels of investment in the network to allow for projected growth. These interests are accounted for in Wellington Electricity's asset management practices through compliance with legislation, engagement and submissions as required, engagement in policy development processes, Emergency Response Plans, and Environmental Management Plans.

3.6.1.6 Industry Organisations

The interests of industry organisations such as the Institute of Professional Engineers NZ, Electricity Engineers Association and Electricity Networks Association are identified through regular contact at executive level, attendance at workshops, and involvement in working groups. Industry organisations expect that good industry practice is followed with a continuous improvement focus. These interests are accounted for in Wellington Electricity's asset management practices through training and development of competencies, and alignment of asset strategies with industry frameworks and practices.

3.6.1.7 Staff and Contractors

Staff and contractors' interests are identified through individual and team discussions, regular meetings, direct business communications and contractual agreements. They are primarily interested in a safe and enjoyable working environment, job satisfaction, fair reward for services provided, mitigation of workplace hazards and work continuity. These interests are accounted for in the asset management practices through health and safety policies and initiatives, performance reviews, and forward planning of work.

3.6.1.8 Shareholders

Shareholder interests are identified through governance, Board meetings, Board mandates, the business plan and strategic objectives. Shareholders expect safety to be non-negotiable, a fair return for their investment, compliance with legislation, good working relationships with other key stakeholders through meaningful engagement, and effective management of the network and business. These interests are accounted for in the asset management practices through governance processes, compliance with legislation, service levels and meeting budget.

3.6.2 Managing Potential Conflicts between Stakeholder Interests

Conflicts in stakeholder interests are managed on a case-by-case basis by balancing risks and benefits. This will often involve consultation with the affected stakeholders and the development of innovative "win-win" approaches. However, safety is the priority when managing a potential conflict in stakeholder interests. Wellington Electricity will not compromise the safety of the public, its staff or service providers.

Wellington Electricity is a member of the Electricity and Gas Complaints Commissioner Scheme, which provides a dispute resolution process for resolving consumer complaints. Wellington Electricity's Use of System Agreements provide a dispute resolution process for managing conflict with retailers.

3.7 Operating Environment

Wellington Electricity operates within the context of the wider New Zealand business environment and the global economy. This includes the financial, legislative and regulatory environments, and the need for the business to assess changes in technology.

3.7.1 The Changing Technology Environment

There continues to be much interest around smart grids and smart technologies and how these will impact transmission and distribution networks, metering, central generation and retail, as well as at consumer level with markets developing to deliver choices for homes and businesses.

For example, the availability of affordable electric vehicles (EVs) has the potential to significantly alter electricity delivery and usage patterns. It is expected that the adoption rate of EVs in New Zealand will increase over the longer term based on:

- New Zealand's high level of renewable energy generation (over 80%) being an ideal match for EVs, which will be seen as an appealing option for environmentally conscious consumers;
- Constantly evolving energy storage systems, electric drives and charging technologies improving the efficiency and range of EVs; and
- EVs offering lower running costs than traditional internal combustion engines due to the higher cost of fossil fuels and the higher efficiency of energy conversion from battery storage.

The expected uptake of EVs in future years and the resultant increase in usage volumes is regularly monitored to determine the likely network impact. There is similar interest in the uptake of distributed photovoltaic (PV) generation. The impact of new technology such as EVs and PV and how they relate to maximum demand and energy forecasting is discussed further in Section 7.3.

Wellington Electricity supports the electrification of transport as a significant means of reducing carbon emissions. The existing agreement to supply the electric trolley bus network is due to expire in 2017, with many of the assets, including cables, transformers and mercury arc rectifiers dating back to the 1940s and are now past their end of life. The electric trolley bus agreement remains silent on the economic means for life extension with current assets funded to conclude service in 2017. Wellington Electricity is working with Regional and City Councils on new technology opportunities to continue electric public transport services in Wellington beyond 2017.

There is potential for emerging technologies to improve the way in which Wellington Electricity manages its network, and to complement traditional electricity assets. For example, the use of PV generation coupled with storage to support daytime peaking areas of the network, e.g. central business districts, may provide a cost-effective alternative to capacity-driven network reinforcement.

By design the Wellington Electricity network already has a number of features which allow for "smart" network management including:

- Closed ring feeders with segmented differential protection to isolate faults while leaving healthy sections in service;
- Remote indication and control via SCADA at over 230 sites, which allows for network management from the Wellington Electricity control room; and
- On demand load management via the existing ripple control system.

Because of the uncertainty and fast changing nature of the emerging technologies, Wellington Electricity's approach is to:

- Track trends and forecasts in the uptake of new technology;
- Incorporate the range of potential impacts of new technology into our load and energy forecasts (Section 7.3);

- Adjust tariff structures to provide incentives to invest in new technology to avoid peaks; and
- Where efficient, use and support new technology within Wellington Electricity's own operations, for example EVs and the installation of charging stations.

3.7.2 The Financial Environment

Wellington Electricity's financial performance is primarily determined by the regulatory price control set by the Commission under the DPP and the cost of debt funding available from global debt capital markets.

The Commission re-set the DPP for the five year period beginning 1 April 2015 which led to a reduction in Wellington Electricity's price for delivering electricity supply by an average of 10% as at 1 April 2015. The 2015 DPP price reset included the Commission's forecast of electricity consumption growth on Wellington Electricity's network, which is a key factor in setting the starting price for each five year price-quality path. As noted in the 2015 AMP, the Commission forecast CPRG of 0.45% per annum which was significantly different to Wellington Electricity's actual network CPRG growth rate of around -1.46% per annum based on a decline in consumption of around 1.1% per annum.

The divergence between the Commission's forecast of growth versus a real decline has the potential to lead to significant revenue under-recovery for Wellington Electricity. Whether or not this shortfall actually occurs is also heavily influenced by weather conditions. This is highlighted by the increase in energy volumes on the network in 2015/16.

The impact of weather and the clear difficulty in accurately forecasting energy consumption has highlighted the unsatisfactory volatility Wellington Electricity faces in its revenues from year to year. Wellington Electricity has submitted to the Commission that a revenue cap approach, which mitigates the consumption forecasting uncertainty, is a more appropriate form of price control. Such an approach would better support energy efficiency initiatives for consumers and be consistent with other international regulatory regimes such as the United Kingdom and Australia. The Commission is currently considering this as it completes a review of the Input Methodologies in 2016, for which any change will take effect in 2020. In the meantime Wellington Electricity will continue to manage its financial performance in a prudent manner, aligning expenditure with revenues as best possible, whilst ensuring the quality of supply is maintained.

Wellington Electricity continues to access global debt capital markets to ensure it has appropriate financing facilities available to meet the investment plans outlined in this AMP.

3.7.3 Legislative and Regulatory Environment

Wellington Electricity is subject to a range of legislative and regulatory obligations. Wellington Electricity has regard to these regulatory and legislative obligations in developing best practice asset management policies and procedures that underpin this AMP. Wellington Electricity regularly engages with the Authority and the Commission through active participation in working groups, conferences, workshops, submissions on various matters, and regular information disclosures. The legislative and regulatory obligations are detailed below.

3.7.3.1 Health and Safety at Work Act 2015 (HSW Act 2015)

The HSW Act 2015 brings about a number of changes in the way Wellington Electricity conducts its outsourced field activities. Under the Act, there are greater obligations for the Principal (e.g. Wellington

Electricity) to ensure that those contracted to do its work (e.g. Northpower, Treescape, etc), and their subcontractors are free from harm and have ensured safety outcomes are achieved, and that risk is considered and controls adopted so that health and safety is well managed in the workplace.

Building on its good safety and environmental record, and consistent with the requirements of the HSW Act 2015 as well as the company's drive for continual improvement, Wellington Electricity is giving increased focus on potential safety and environmental risk at the early stages of a project. Rigorous risk assessments are being conducted with contractors prior to the project being approved, with continual monitoring throughout the project lifecycle of potential changes in risk. The cost and time implications of this increased focus are being factored into project budgets and schedules.

The main changes introduced by the HSW Act 2015 and which form the primary focus for Wellington Electricity are:

- The concept of the 'person conducting a business or undertaking' (PCBU), including the duty of officers;
- Consultation, cooperation and coordination between PCBUs;
- Extension of hazard management to incorporate risk management at worker level; and
- Worker engagement, participation and representation.

A compliance management system is being implemented by Wellington Electricity that supports business processes relevant to the HSW Act 2015 as well as the NZS 7901 Public Safety Management obligations and timeframes that are reported quarterly to the Board.

3.7.3.2 Price Quality Compliance

Wellington Electricity is subject to price and quality control contained within Part 4 of the Commerce Act 1986. Wellington Electricity's maximum weighted average price cap for providing regulated lines services is set out in the 2014 Determination and applies for the regulatory control period from 1 April 2015 to 31 March 2020. Wellington Electricity must also supply electricity based on the two quality level targets set by the Commission.

3.7.3.3 Information Disclosure

Wellington Electricity is subject to information disclosures on an annual basis as well as responses to other information requests. To ensure accurate preparation and reporting of information, the business processes and information systems are aligned to the Information Disclosure Determination 2012 to ensure that information is accurate and available in the prescribed form.

3.7.3.4 Model Use of System Agreement (MUoSA)

Wellington Electricity supports consumers' right to choose how they participate in the load control market. Since 2012 the Authority has continued to indicate that at some point it would consider mandating the MUoSA through regulation. This approach by the Authority has tended to hinder any negotiations with retailers as they have sought to wait until the Authority regulated the agreements. In February 2016, the Authority commenced its consultation on regulating the agreements to set the terms in which retailers and EDBs contract for the supply distribution services.

3.7.3.5 Government Policy - Major Infrastructure projects

Major infrastructure projects driven by Government policy have an impact upon Wellington Electricity's network. Ultra-fast Broadband (UFB) is a positive initiative for New Zealand and the rollout is currently being undertaken in Wellington by the telecommunications infrastructure provider Chorus. The rollout is governed by an interface management plan, contained within a pole connection agreement, to meet the safety obligations between the two PCBUs.

3.7.3.6 Requirements Driven by Local Authorities

Wellington Electricity must comply with local authority requirements. Wellington Electricity monitors notified resource consent applications and proposed changes to district plans, providing comment and submissions when required.

3.7.3.7 The Electricity (Hazards from Trees) Regulations 2003 (Tree Regulations)

Wellington Electricity manages vegetation around its network in accordance with the requirements of the Tree Regulations, as vegetation close to network assets has the potential to interfere with the reliable and safe supply of electricity. The Tree Regulations prescribe distances from electrical conductors within which vegetation must not encroach. Wellington Electricity is required to advise tree owners of their obligations for the safe removal of vegetation. Wellington Electricity has a Vegetation Management Agreement in place with an external service provider to manage vegetation around the network. Wellington Electricity's vegetation management programme has resulted in a reduction in the number of tree related faults on the network.

Section 4:

Service Level and Performance

4 Service Levels and Network Performance

Wellington Electricity is committed to providing consumers with a safe, reliable, cost effective and high quality energy delivery system. This section describes Wellington Electricity's targeted service levels to achieve this objective. The measures and targets presented flow directly from our mission and Business Plan. This section also explains the basis for measuring the service level performance and how Wellington Electricity has performed historically. There are four areas where services levels have been established:

- Safety Performance;
- Reliability Performance;
- Asset Performance; and
- Customer Experience.

The service levels also incorporate feedback received from the stakeholder groups discussed in Section 3.6.

4.1 Safety Performance Service Levels

Wellington Electricity has continued to build on the foundation set by past health and safety performance. It is a member of the Electricity Engineers Association (EEA) and supports initiatives the EEA undertakes in providing leadership, expertise and information on technical, engineering and safety issues across the New Zealand electricity industry.

Continual improvement in managing health and safety is core to Wellington Electricity and involves ongoing review of health and safety practices, systems and documentation.

Wellington Electricity welcomes the change in Work Safe New Zealand legislation as an ongoing approach to continuing improvement to workplace safety and focus on effective identification and management risk to protect the welfare of workers engaged in delivering our services.

Within this context of continuous improvement, four primary measures have been adopted:

- Lost time injury frequency rate (LTIFR);
- Total notifiable event frequency rate (TNEFR) from 4 April 2016;
- Incident and near miss reporting; and
- Corrective actions from site visits closed.

LTIFR and TNEFR are lagging indicators of safety performance, while incident reporting and site visits to engage and consult with the workforce are leading indicators that help build a supportive safety culture and reinforce positive safety behaviours. Past performance and targets for the planning period for each measure are set out below.

4.1.1 Lost Time Injury Frequency Rate

Wellington Electricity's staff and contractors recorded zero Lost Time Injury (LTI) incidents in 2015. This resulted in a 2015 LTIFR of 0.00 per million hours worked and a two year rolling average of 1.08.

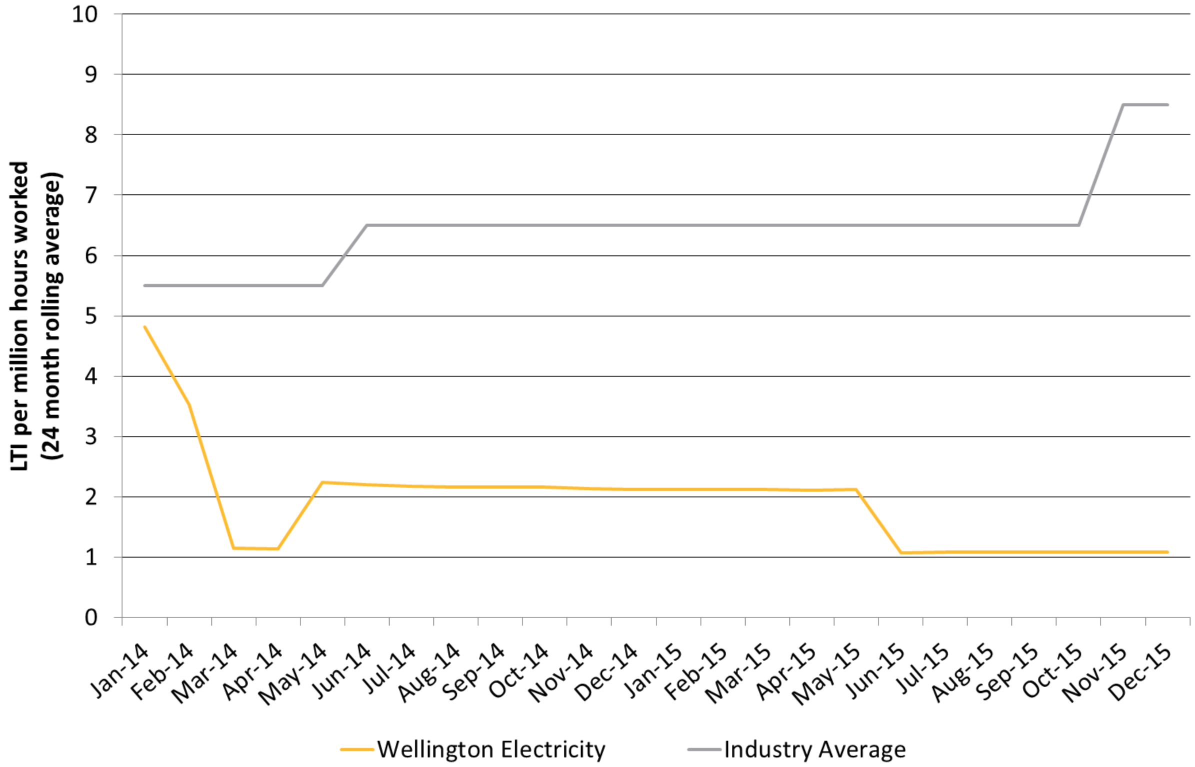


Figure 4-1 Lost Time Injury Frequency Rate

4.1.1.1 Planning Period Target

Wellington Electricity's target for the 10-year planning period is to achieve a zero LTI and LTIFR over the whole period.

4.1.2 Total Notifiable Event Frequency Rate

The HSW Act 2015 introduces "notifiable events" which comprise notifiable injuries, notifiable incidents and fatalities. The reference to "serious harm" within Section 16 of the Electricity Act 1992 has been replaced with Section 23 of the HSW Act 2015 reference to "notifiable injury, incident or illness".

This is a new lag performance measure commencing in 2016 and has been included into service provider performance indicators.

4.1.2.1 Planning Period Target

Wellington Electricity's target for the 10 year planning period will be set in the 2017 AMP.

4.1.3 Incident and Near Miss Reporting

During 2015 Wellington Electricity continued to implement initiatives aimed at increasing reporting rates of "incidents" and "near miss" events. Increased reporting is a measure of open communication across the business and allows for continuous improvement from small incidents which in turn reduces the likelihood of serious events.

Total event reporting increased again in 2015 to a total of 546 events. Approximately 70% of all reported events were classified as minor, 25% were classified as moderate, whilst only 1% were of a serious nature. The total number of near miss events reported during 2015 was 281, a slight decrease on the previous year's near miss reports.

Reporting of loss events (an incident which resulted in some form of loss, damage or injury) during 2015 slightly increased with a total of 242 incidents reported. The majority of these were of a minor nature and would not constitute notifiable events.

4.1.3.1 Planning Period Target

Wellington Electricity's target for the 10 year planning period is to achieve at least 500 near miss events reported per annum.

4.1.4 Corrective Actions from Site Visits

The revised Wellington Electricity Field Assessment Standard provides for the categorisation of corrective actions resulting from field assessments of worksites by severity and monitoring of close out times.

The majority of assessment findings were non-conformance with Wellington Electricity technical standards. Actions undertaken in 2015 to address these non-conformances include: one-on-one training with the Wellington Electricity Field Compliance Assessor; attendance at traffic management training; setting targets for the number of assessment reports to be undertaken by project managers, improved scrutiny of the quality of assessment reports, and provision of report writing and corrective action identification guidance.

There has been a decrease in the ratio of corrective actions identified per assessment against 2012 levels, which can be inferred from Figure 4-2. Monitoring will continue to ensure that this trend is continued and improved upon. The majority of safety actions identified were a result of non-compliance with Wellington Electricity PPE requirements and this is being addressed with contractors.

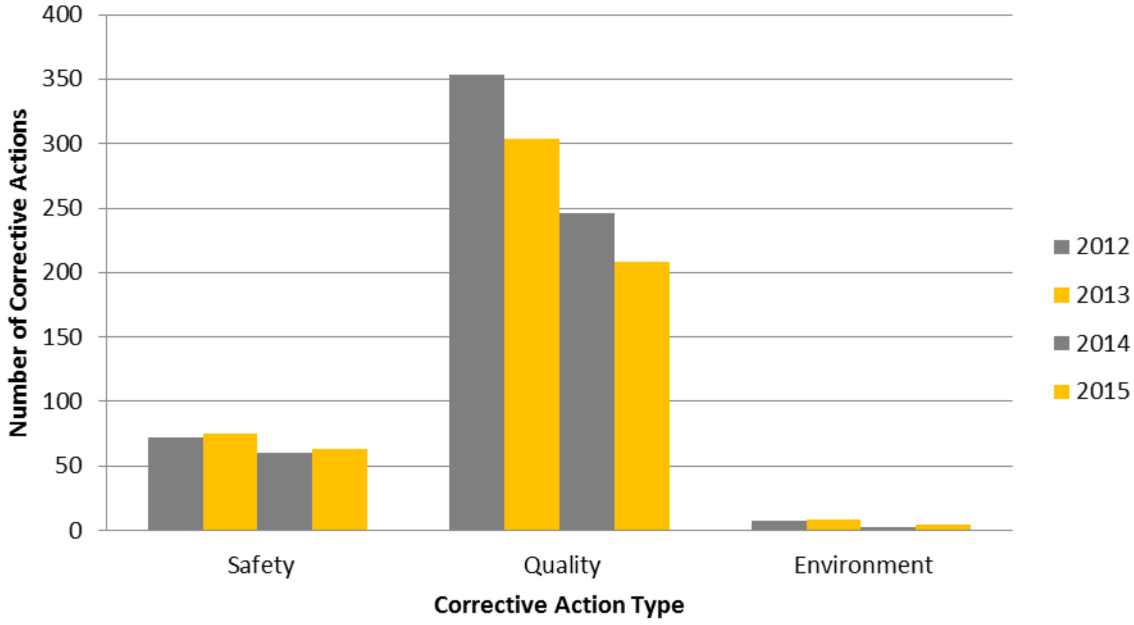


Figure 4-2 Corrective Actions arising from Assessments 2012-2015

4.1.4.1 Planning Period Target

Wellington Electricity's target for the 10 year planning period is to maintain the current level of field compliance assessments and:

- Reduce the safety related corrective actions to below 50 per annum;
- Reduce the quality related corrective actions required to below 100 per annum; and
- Maintain the environment related corrective actions required at below five per annum.

4.1.5 Health and Safety Initiatives

During 2016 focus will be placed on the following areas to further improve performance:

- Increase the timeliness of close-out of assessments;
- Reduce the number of Corrective Actions identified without compromising standards;
- Reduce the number of high classification events;
- Reduce the number of repeat non-conformances;
- Expand the risk assessment process and client/contractor communication; and
- Increase site visits to engage and consult workers on safety culture and supportive behaviours.

4.2 Reliability Performance Service Levels

Network reliability is measured using two internationally recognised performance indicators, SAIDI[12] and SAIFI[13].

- SAIDI is a measure of the total time, in minutes, electricity supply is not available to the average consumer connected to the network in the measurement period; and
- SAIFI is a measure of the total number of supply interruptions that the average consumer experiences in the measurement period.

When taken together SAIDI and SAIFI provide an objective basis for assessing the quality of supply received by consumers connected to the network. SAIDI and SAIFI are reported annually to the Commission.

Wellington Electricity's reliability performance has been, and continues to be, one of the best in New Zealand, as illustrated in Figure 4-3 and Figure 4-4.

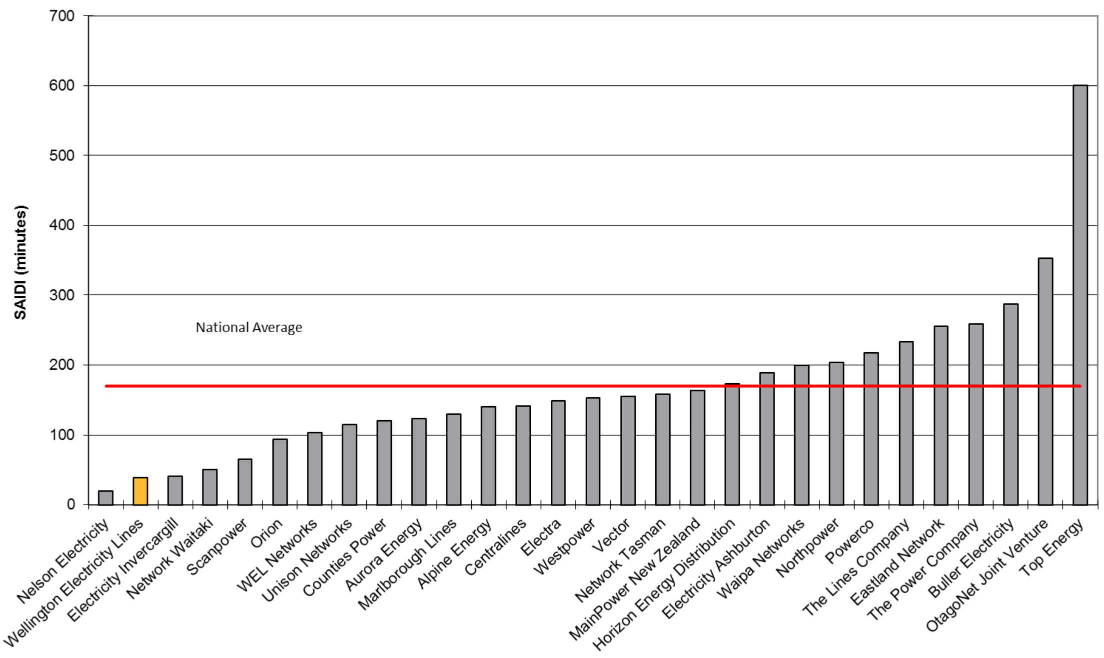


Figure 4-3 National SAIDI by EDB for 2014/15

12 System Average Interruption Duration Index

13 System Average Interruption Frequency Index

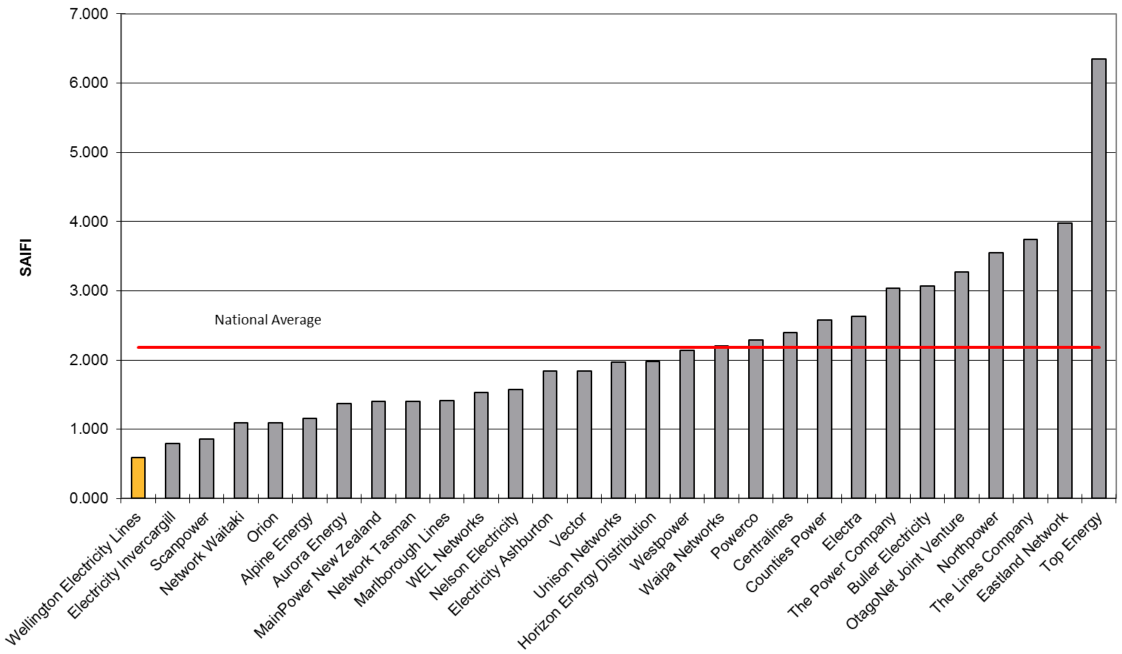


Figure 4-4 National SAIFI by EDB for 2014/15

The Commission requires non-exempt EDBs to report the actual reliability performance of the network against the limits set by the Commission. Wellington Electricity's historical performance is shown in Figure 4-5.

Regulatory Year	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16 Forecast [14]
SAIDI limit	40.74	40.74	40.74	40.74	40.74	40.63
SAIDI actual	34.74	45.88	43.29	78.88	38.757	31.4
SAIFI limit	0.60	0.60	0.60	0.60	0.60	0.625
SAIFI actual	0.537	0.715	0.573	1.107	0.586	0.56

Figure 4-5 Wellington Electricity Reliability Performance 2010-2015

While Wellington Electricity exceeded the quality limits between 2011/12 and 2013/14 due to the extraordinary weather related events that occurred in those years, both the SAIDI and SAIFI reliability limits were within the DPP quality standards for the 2014/15 year and are forecast to again be within limits for 2015/16 year. Changes in the 2015 DPP reset adjusted the boundary value for major events (referred to as the TMED threshold) which will also improve compliance with regulatory quality targets.

4.2.1 Underlying Cause of Network Outages in 2015

Analysis of the underlying causes for all network or equipment related faults is undertaken by Wellington Electricity. A breakdown of faults on the network by fault type, excluding major event days for 2014/15, is shown in Figure 4-6.

[14] Forecast as at 29 February 2016, and assuming average historical performance for March.

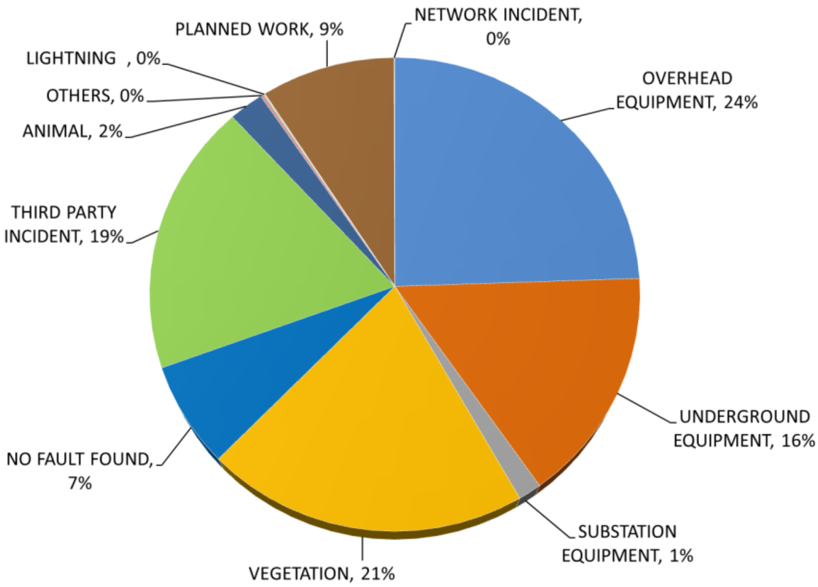


Figure 4-6 SAIDI Performance by Fault Type, 2015

In 2014/15 49% of faults were related to events outside of the network, with only 41% related to network equipment (12.2 SAIDI minutes out of 38.8). Fault causes directly a result of an asset failure or an indicator of systematic type issues are discussed in Section 6. Fault causes related to events outside of the network are discussed in Section 5.

4.2.2 Reliability Performance Targets

The regulatory regime that applies to Wellington Electricity sets reliability caps and collars for each year from 2015/16 to 2019/20. The caps and collars are set using historical data at one standard deviation above and below the mean (target). The caps and collars are the maximum and minimum reliability outcomes for which a reward or penalty of $95,091[15] per SAIDI minute and $6,308,301 per SAIFI unit apply if the company's performance is better than or below the target respectively. In addition, the Commission has retained a compliance test for reliability which is based on meeting the cap (mean plus one standard deviation) in the current year or both of the immediately preceding two years. The target, caps and collar for Wellington Electricity are presented in Figure 4-7.

Regulatory Period 2016-2020	Annual SAIDI	Annual SAIFI
Target	35.44	0.547
Cap	40.63	0.625
Collar	30.24	0.468

Figure 4-7 Wellington Electricity Annual Regulatory Reliability Targets and Limits

The data set used to establish these performance targets is based on the 10 years from 2004 to 2014, known as the reference period. The first five years of the reference period experienced benign weather relative to the second five years. Consequently, the targets represent a performance level that is better than

[15] The rewards and penalties relate to Wellington Electricity only and are calculated on an EDB by EDB basis

what would be expected given recent weather trends. However this is partially offset by the lower boundary values used for the TMED threshold which acknowledges future storm activity should contribute a lower impact on actual values.

The targets for SAIDI and SAIFI are shown in Figure 4-8, and reflect Wellington Electricity's view that it is adequately funded to maintain network reliability at current levels, subject to energy volume through the network meeting expectations. There is uncertainty around the calculation of new targets from 2020/21 onwards, with the methodology likely to be set as part of the 2016 IM Review.

Regulatory Year	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
SAIDI target	35.44	35.44	35.44	35.44	35.44	35.44	35.44	35.44	35.44	35.44
SAIFI target	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547	0.547

Figure 4-8 Network Reliability Performance Targets

The SAIDI and SAIFI targets against the historical performance are shown in Figure 4-9 and Figure 4-10.

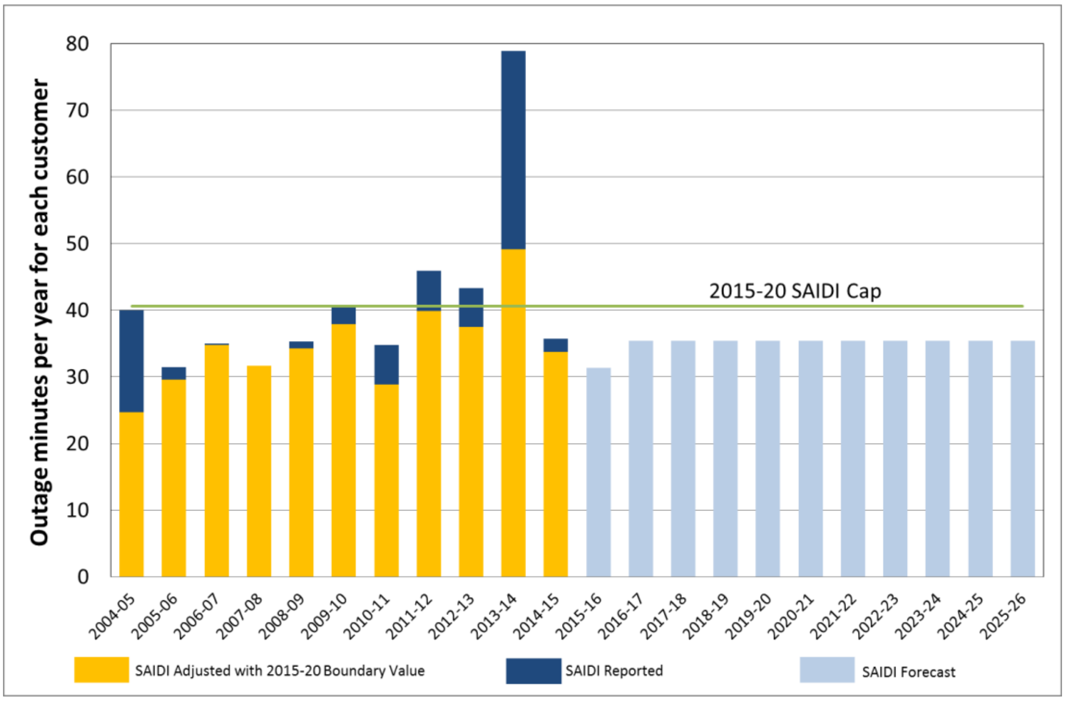


Figure 4-9 Wellington Electricity SAIDI Performance

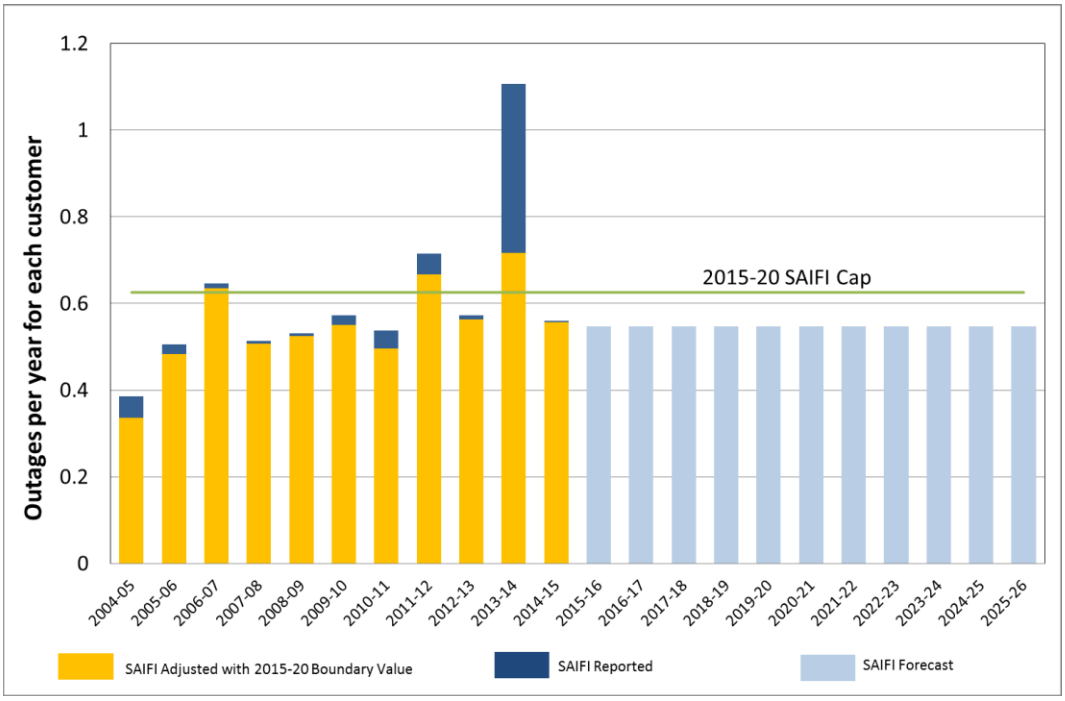


Figure 4-10 Wellington Electricity SAIFI Performance

4.2.3 Reliability Initiatives

Reliability Initiatives

Managing reliability is at the core of Wellington Electricity's continuous improvement process. Key components of this process include:

- Mitigating, where practicable, the impact of severe storms by using line sectionalisers and reclosers and by employing well-practiced emergency restoration plans;
- Analysing all significant outages (over 0.45 SAIDI minutes) to identify root causes and recommendations to prevent recurrence;
- Monitoring trends in outages causes and other asset failures to identify changes in maintenance practices and to confirm assets to be upgraded;
- Monitoring of field response and repair times for major faults to identify causes of prolonged outages and develop strategies to improve restoration times;
- Analysis of worst performing feeders
- Further refinement of the targets to reflect consumer segments (for example, Wellington CBD requires a higher level of security than rural consumers);
- Extending risk based analysis to cover conductors and underground cables; and
- Further analysis of wind speed and wind direction forecasting.

4.3 Asset Performance Service Levels

The load factor or utilisation of an asset reflects consumer demand profiles, the geography of the region and historic network design and configuration decisions. Wellington Electricity's predominantly urban network results in a higher than average utilisation and load density. The asset performance targets used by Wellington Electricity relate to the efficiency with which the company 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.

4.3.1 Planning Period Targets

Wellington Electricity aims to maintain the high level of utilisation of asset at current levels, in line with other networks that display similar characteristics. Wellington Electricity has a very high customer density but below average energy density per ICP. The utilisation targets are shown in Figure 4-11.

	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[16]	61.7	30.7	5.9	39.2	187.7	12.2	16,306
Performance	51.2	40.1	4.2	116.0	499.4	35.4	14,118
Targets 2016-2026	>50%	>40%	<5%	-	-	-	-

Figure 4-11 Wellington Electricity Asset Performance Targets to 2026

Wellington Electricity is better than the industry average in three of the utilisation targets and is expected to remain at the current levels over the planning period.

4.4 Consumer Experience Service Levels

Wellington Electricity has two customer related performance measures. These are:

- Power restoration service level targets; and
- Contact Centre performance.

Each is described below.

4.4.1 Power Restoration Service Levels

Wellington Electricity's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to three different categories of consumers: CBD/Industrial, Urban and Rural. These service levels reflect previous feedback from our consumers and are agreed between Wellington Electricity

[16] Values as of 2015, Source: PWC Compendium

and all retailers. They provide Wellington Electricity with financial incentives to restore supply within the maximum restoration times, provided that safety is not compromised.

The geographical region by customer category is shown in Figure 4-12.

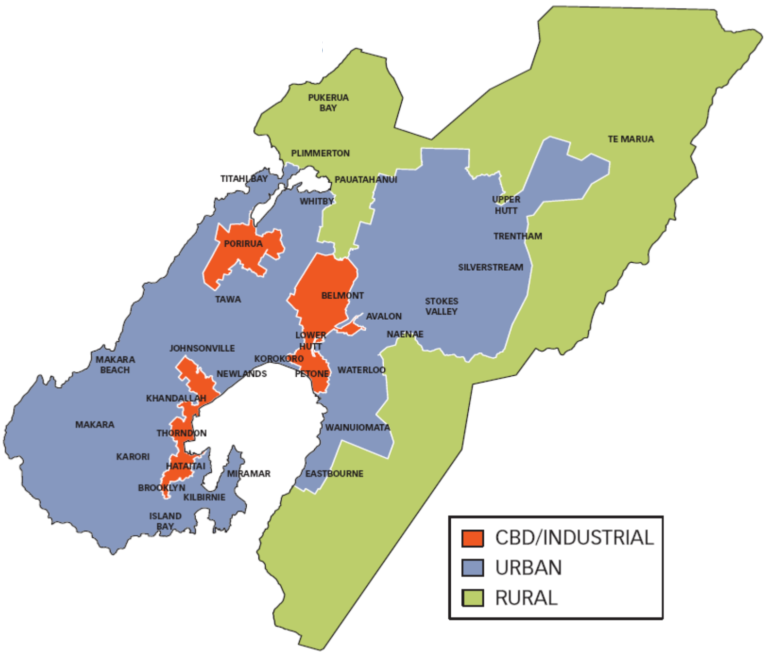


Figure 4-12 Location of Customer Category Areas

4.4.1.1 Planning Period Targets

The targets for the power restoration service levels remain consistent over the planning period 2016-2026, as set out in Figure 4-13.

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

Figure 4-13 Standard Power Restoration Service Level Targets 2016-2026

4.4.2 Contact Centre Service Levels

Wellington Electricity has developed a set of key performance indicators (KPIs) and financial incentives that provide service level targets for the Contact Centre (Telnet). These service levels have been in place since 2013. Due to the high level of consumer satisfaction with Contact Centre performance (90% to 94%), it is expected the targets and performance measures will remain broadly the same for the planning period from 2016 to 2026. As consumer engagement initiatives progress and the contractual arrangements with the Contact Centre have been renewed, improvements continue to be made in service levels and measures of key performance by Telnet.

Examples of changes that have been made to Contact Centre processes include:

- More rigour around how the Wellington Electricity/Telnet information knowledge base is managed;
- The introduction of measured outage communications KPIs between our contact centre and our primary field service contractors;
- Improved Contact Centre performance reporting and review; and
- Clearer work flow prioritisation.

4.4.2.1 Contact Centre Service Levels

There are currently nine service level performance measures for the Contact Centre. These are:

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

2. 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.

3. 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 also an international standard for utility call centres, which recognises that calls may be abandoned for a variety of reasons, including some not related to call centre performance. However an abandonment rate above 4% may be indicative of an issue with the call centre service.

4. Outage Communications (B1): This is a measure of the time taken to initially notify of an outage. Retailers will be notified, and the Wellington Electricity website updated, within five minutes of Telnet receiving notice of an outage affecting 10 or more customers.

5. Outage Communications (B2): This is a measure of ongoing outage updates. Retailers and the Wellington Electricity website will be updated with changes (if any) to affected customer numbers and Estimated Time of Restoration (ETR) at least every 30 minutes (+/- 5 minutes) during the outage.

6. Outage Communications (B3): This KPI measures that more accurate ETR information is provided within a reasonable time. Within 90 minutes of Telnet receiving notice of an outage affecting 10 or more customers, Telnet will contact the Network Control Room (NCR) or Northpower (as appropriate) to get an accurate updated ETR. Retailers and the Wellington Electricity website will be updated.

7. Outage Communications (B4): This is a measure of ongoing outage updates for more prolonged outages. Retailers and the Wellington Electricity website will be updated with changes (if any) to affected customer numbers and ETR at least every 120 minutes (+/- 5 minutes) during the outage.

8. Outage Communications (B5): This is a measure of the time taken to notify outage restoration. Retailers will be notified, and the Wellington Electricity website updated, within five minutes of Telnet receiving notice of outage restoration.

9. Customer satisfaction (C1) - All customer contact should contribute to customer satisfaction in dealings with the service provider when representing Wellington Electricity. Measurement is by way reviewing a random sample of calls of a sample selected by Wellington Electricity.

Note that the Outage Communications KPIs (B1 – B5 above) have only been in place since January 2015 so no meaningful annual data on actual performance is available to at the time of writing.

Figure 4-14 sets out the results for the numeric A1 to A3 measures for the 2015 year.

SL	Service Element	Measure	KPI	2015 Actual
A1	Overall service level	Average service level across all categories	>80%	90.05%
A2	Call response	Average wait time across all categories	<20 seconds	13.2 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	<4%	1.53%

Figure 4-14 Contact Centre Service Level Performance

Customer satisfaction performance (C1) is shown in Figure 4-15. C1 is measured by reviewing a sample of 10 calls for the quality of interaction with callers. The target is to reach a minimum of 80% based 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 public.

SL	Service Element	Measure	KPI	2015 Actual
C1	Specific Contact Centre experience	Wellington Electricity is properly represented during specific calls	Qualitative assessment 80%	92.3%

Figure 4-15 Customer Satisfaction Service Level Performance

4.4.2.2 Planning Period Targets

The Contact Centre service level targets are to provide consistent performance over the planning period 2016-2026. These are shown in Figure 4-16.

SL	Service Element	Measure	Target
A1	Overall service level	Average service level across all categories	>80%
A2	Call response	Average wait time across all categories	<20 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	<4%
B1	Initial Outage Notification	Energy retailers notified and the Wellington Electricity website updated within the time threshold	<5 minutes
B2	Ongoing Outage Updates	Regular outage status updates provided	every 30 minutes
B3	Estimated Time of Restoration (ETR) Accuracy	Accurate ETR provided within the time threshold from initial outage notification	<1.5 hours
B4	Ongoing ETR Updates	Regular status updates to prolonged outages provided within the time threshold	within 2 hours
B5	Restoration Notification	Energy retailers notified and the Wellington Electricity website updated within the time threshold from the time of restoration	<5 minutes
C1	Specific Contact Centre experience	Wellington Electricity is properly represented during specific calls	Qualitative assessment 80%

Figure 4-16 Customer Satisfaction Service Level Targets 2016-2026

Section 5:

Risk, Resilience, Asset Management Frameworks

5 Safety, Risk, and Asset Management Frameworks

This section describes Wellington Electricity's risk management and asset management frameworks, processes and governance. It also sets out Wellington Electricity's approach to resilience and health, safety and quality. In summary the section covers:

- Quality, safety and the environment
- The risk management framework;
- The asset management framework;
- The investment selection process;
- The delivery processes and service providers;
- The Asset Management Maturity Assessment Tool (AMMAT);
- Existing management of HILP events including emergency response plans and contingency planning; and
- Future management of HILP events

5.1 Quality, Safety and the Environment (QS&E)

Wellington Electricity is committed to providing excellence in QS&E outcomes through application of the following principles:

- All employees and contractors undertake their work in a safe environment using safe work practices;
- 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; and
- Processes are in place to ensure high quality outcomes are consistently achieved.

To support these principles, Wellington Electricity maintains a comprehensive set of health and safety, environmental, and quality policies and procedures.

In accordance with Wellington Electricity's mission, health and safety is given top priority and is a core business value. A Health and Safety Committee meets each quarter to review issues requiring Board governance or guidance. As illustrated in Figure 5-1, a formalised Safety Leadership Structure is in place to help ensure that health and safety leadership is provided throughout the business.

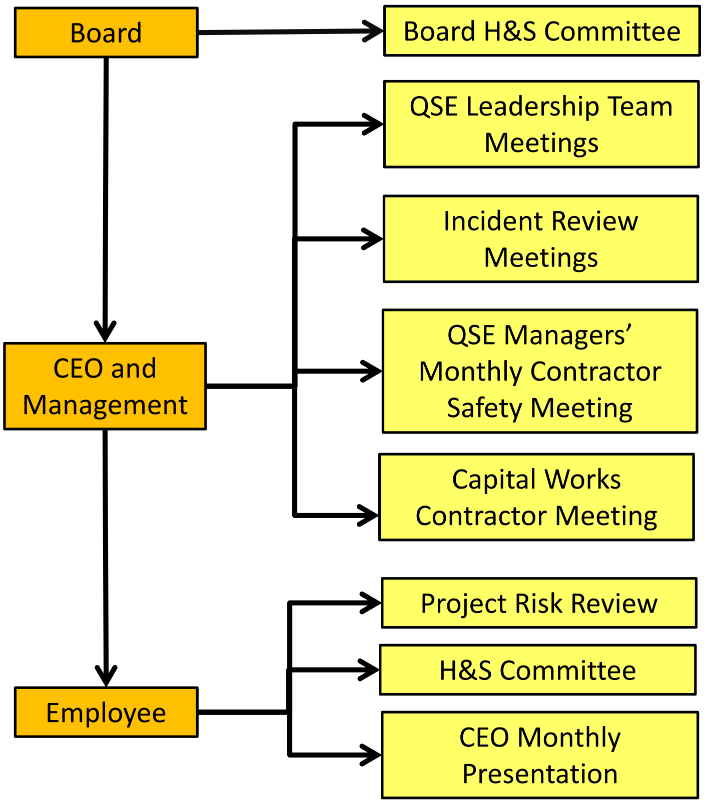


Figure 5-1 Safety Leadership Structure

Wellington Electricity holds a monthly Safety Leadership Committee (SLC) meeting to monitor performance, discuss emerging trends or new issues and progress on key improvement areas. The CEO and senior management team are part of the SLC. 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.

In a similar manner quality and environmental outcomes are managed by Wellington Electricity with employees and contractors required to:

- Take all reasonable steps to ensure that business activities provide an outcome, which minimises environmental impacts and promotes a sustainable environment for future generations; and

- 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.

Wellington Electricity's QS&E outcomes and processes are discussed in more detail below. The associated performance objectives and measures are described in Section 4.

5.1.1 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 public areas and the 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 Regulations 47 and 48 of the Electricity (Safety) Regulations 2010.

The PSMS also meets the requirements of New Zealand Standard Electrical and Gas Industries – Safety Management System (NZS 7901:2008). In 2015 the certification body Telarc reassessed Wellington Electricity against the requirements of NZS 7901 and confirmed that Wellington Electricity was compliant with regulatory 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.

5.1.1.1 School Safety Programme

Wellington Electricity runs an education programme for schools which educates children about electrical safety. The Stay Safe programme is aimed at primary school aged children and offered for delivery in schools around the Wellington region by Wellington Electricity. The programme involves showing a DVD, an 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.

5.1.1.2 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* website which contains interactive safety games and information targeted at young children and parents regarding about network safety and electrical safety around the home.

5.1.1.3 Media Advertising

Wellington Electricity actively raises public awareness about the dangers of living and working around network assets. Wellington Electricity undertakes radio safety campaigns which cover 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. Radio safety campaigns were conducted in 2015 relating to vegetation management, excavation safety and safety disconnections for maintenance around the home.

5.1.1.4 Safety Seminars and Mail Outs

In order to help prevent third party contact with the network, Wellington Electricity works closely with civil contracting companies (third party contractors working around Wellington Electricity assets) and other organisations that, through the nature of their work, need to get closer to the network than normally allowed. This may be in the form of a planning discussion or on-site safety seminars which raise awareness of safe working practices when working around the network and particularly when excavating in the vicinity of existing underground infrastructure.

From time to time Wellington Electricity mails out letters to various contracting sectors focussing on infringements impacting safety around the network.

Wellington Electricity also works with Energy Safety to ensure interactions with the network are conducted safely and investigated where appropriate.

5.1.1.5 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 *"WE* 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. This booklet will be updated in the 2016/17 year to reflect changes resulting from the new health and safety legislation which comes into force in April 2016.

Wellington Electricity continues to develop closer relationships with major contracting groups which is consistent with the HSW Act 2015 and brings about a number of changes in the way Wellington Electricity conducts its outsourced field activities. The HSW Act 2015 requires a greater level of consultation, co-operation and co-ordination in relation to health and safety duties and issues. These changes include the ongoing requirement for due diligence and governance from Board level down and across all parties involved in the supply continuum. All personnel including contractors and volunteers become workers for the purposes of the HSW Act 2015. The fundamental obligation to protect workers, the public and property from harm, remains the core consideration with effective planning and solid communication being paramount to safe and effective work management. Wellington Electricity is reviewing processes to ensure the systems and operating standards reflect the new requirements.

5.1.1.6 Information and Value Add Services

Wellington Electricity provides an information service to reduce the risk of public safety and incidences of damage to assets or property. The service is available through a 24 hour freephone number.

Figure 5-2 shows the number and type of information service requests over the last five years.

Information and Value Add Services	Year				
	2011	2012	2013	2014	2015
Service Map Requests	6,286	9,154	9,926	12,147	23,504
Cable Locations	2,165	6,149	2,846	2,251	1,932
Close Approach	95	181	328	80	376
Standovers	123	95	140	182	147
High Load Permits	25	77	35	33	37
High Load Escorts	5	7	3	5	2

Figure 5-2 Summary of Information Service Requests 2010-2015

Since 2010 there has been a significant increase in calls relating to service map requests. The increase is attributed primarily to commencement of the UFB rollout in the Wellington region.

5.1.2 Workplace Safety and Initiatives

Wellington Electricity has a number of workplace safety initiatives in place. These are discussed below.

5.1.2.1 Safety Breakfasts

Wellington Electricity regularly arranges safety breakfasts for all its external 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 these sessions.

5.1.2.2 Annual Worker Safety Workshop

Wellington Electricity arranges a half day safety seminar for all its workers and closely associated PCBUs and their key workers on an annual basis. The aim of these seminars is to reinforce Wellington Electricity's desired behaviours through direct interface with the Wellington Electricity CEO, keynote speakers and other subject matter experts. In 2015 the safety seminars included;

- Presentation on a serious harm incident which occurred to a contract worker on a different network;
- A well-known human factors expert speaking about how errors can be made despite, and in some cases because of, systems and processes being in place; and
- Presentation of contractor safety achievement awards to publically recognise workers who demonstrate a positive approach to safety throughout the year.

5.1.2.3 Site Safety Visits

Wellington Electricity ensures its workers undertake familiarisation visits to sites where contractors are working on the network. The Site Safety Visits are used to confirm understanding and implementation of corrective actions and to discuss safety systems and opportunities for improvement.

5.1.2.4 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. All operational personnel working in the field are required to hold the appropriate competency authorisation for the work being conducted.

Wellington Electricity ensures its personnel 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; and
- Basic Traffic Control management.

5.2 Risk Management

Wellington Electricity has adopted the *ISO 31000:2009 Risk management – Principles and Guidelines* standard to provide a structured and robust framework to managing risk, which is applied to all business activities, including policy development and business planning. Wellington Electricity's risk framework is discussed in Section 5.2.2. Risk management is an integral part of good asset management practice. Wellington Electricity's approach to managing asset specific risks is discussed in Section 6.

5.2.1 Risk Management Accountabilities

Wellington Electricity's Board has overall responsibility for the governance of the business, including approval of the risk management framework. Board oversight of the risk management process is delegated to the Audit and Risk Committee, a sub-committee of the Board. This Committee is updated bi-annually by the CEO as part of the regular management reporting functions in line with the risk management framework.

The CEO is accountable for the performance of the business and as such the effectiveness of the controls being employed to manage the risk from occurring. While the CEO is held accountable by the Board, the management team have assigned responsibilities for ensuring controls are implemented and well managed so that risks are reduced to an acceptable level. The responsibility of controls are assigned to managers and bi-annually reviewed to ensure they remain relevant and that the risk environment has been assessed for new risks or changes to the risk profile. Some of the key controls are listed in Section 5.2.3.

5.2.2 Risk Management Framework

Wellington Electricity's approach to risk management is illustrated in Figure 5-3.

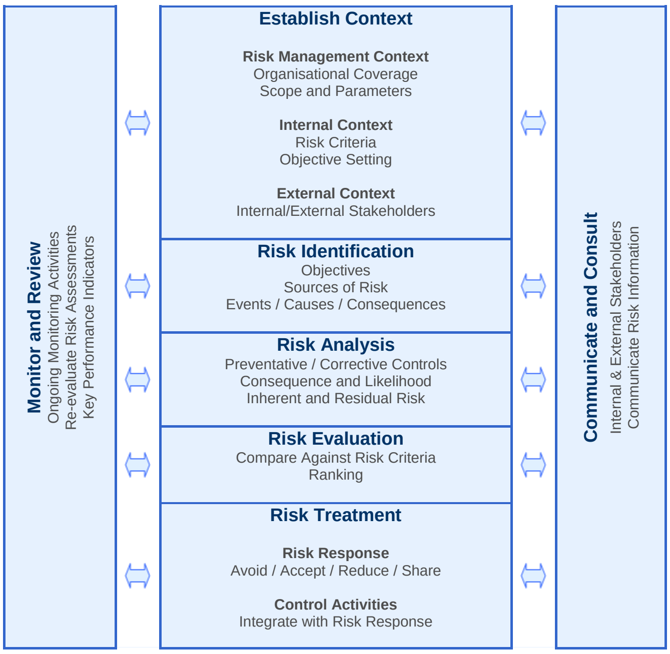


Figure 5-3 Wellington Electricity's Risk Management Process, adapted from ISO 31000:2009

The risk management process as illustrated above covers the following five process steps:

Establish Context. This takes into account company objectives, the internal and external operating environment (discussed in Section 3.7), and risk criteria;

Risk Identification. Risks are identified through operational and managerial processes. Wellington Electricity has grouped its risk into seven categories. These are:

- Health and safety (employees, public and service providers);
- Environment (land, vegetation, waterways and atmosphere);
- Financial (cash and earnings losses);
- Reputation (media coverage and stakeholders);
- Compliance (legislation, regulation and industry codes);
- Customer service/reliability (quality and satisfaction); and
- Employee satisfaction (engagement, motivation and morale).

Risk Analysis. Analysis is undertaken using both qualitative and quantitative measures and assessed in terms of likelihood (chance of the event occurring) and consequence (impact of the event occurring). Consequence and likelihood tables have been established considering Wellington Electricity's asset planning objectives. Consequence scales have been developed by describing levels of consequence for each criteria ranging from catastrophic (the level that would constitute a complete failure and threaten the survival of the business), to minimal (a level that would attract minimum attention or resources). Likelihood scales have been developed depending on the chance or the likelihood of the event occurring. The risk rating is plotted on a risk chart with its likelihood score on the y-axis and overall consequence on the x-axis.

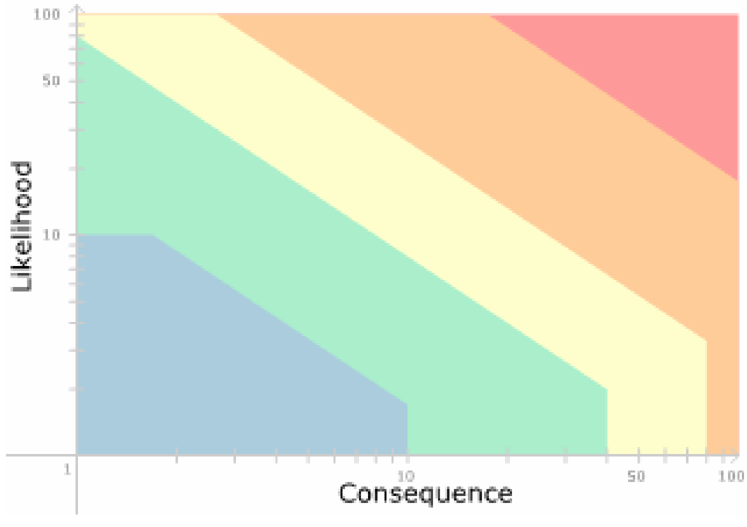


Figure 5-4 Risk Likelihood Consequence Matrix

The risk profiling matrices shown in Figure 5-5 and Figure 5-6 are used to determine the level of the risk or risk rating. The risk rating is a function of likelihood and consequence.

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 5-5 Qualitative Risk Matrix

LIKELIHOOD	CONSEQUENCE				
	Minimal 1.8	Minor 5	Moderate 11	Major 50	Catastrophic 90
Almost Certain 95	171	475	1045	4750	8550
Likely 25	45	125	275	1250	2250
Possible 10	18	50	110	500	900
Unlikely 5	9	25	55	250	450
Rare 3	5.4	15	33	150	270

Figure 5-6 Semi-Quantitative Risk Matrix

Risk Evaluation. Requires the identification of risk controls and assessment of the effectiveness of these controls in reducing or mitigating the risk generates the residual risk rating. This supports Wellington Electricity's decision making process to ascertain which risks need additional treatment and the priority for treatment implementation.

Risk Treatment. Risk treatment involves selecting one or more options for modifying the risk. These options can include avoiding the risk by not commencing or continuing the activity, removing the risk source, changing the likelihood of the risk occurring, changing the consequences, sharing the risk with another party or parties (e.g. contracts and insurance), and retaining the risk by informed decision. Risk treatment plans are developed to address the risk. Controls are introduced to mitigate the likelihood or consequence of the risk. This reduces the inherent risk score to give a residual risk rating.

5.2.3 Key Business Risks and Controls

Risks were updated in December 2015 and this identified no current extreme residual risks and six high residual risks. The overall residual risk rating across the business remains at low.

44 risks were assessed by Wellington Electricity in total. Figure 5-7 shows the fifteen highest risks ranked according to their residual ratings, and then by their inherent risk ratings. The change in residual risk ratings for these risks compared to the December 2014 result is also shown.

Rank	Change (2014 Ranking)	Event	Inherent Rating	Residual Rating
1	▬ (1)	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources).	Extreme	High
2	⬆ (6)	A loss of connection supply from transmission assets.	Extreme	High
3	⬇ (3)	Injury or Damage caused or loss suffered to third parties.	Extreme	High
4	New Risk	Exploitation of IT security.	Extreme	High
5	⬇ (2)	Non-optimum starting price adjustment	Extreme	High
6	⬇ (4)	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets	High	High
7	⬇ (5)	Sub-optimal performance or failure of network assets.	Extreme	Medium
8	⬇ (7)	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
9	⬇ (8)	Release or spread of hazardous materials, Electromagnetic Fields (EMF) or noise to land, ecosystems or atmosphere.	Extreme	Medium
10	⬇ (9)	Mis-Management of a crisis and emergency affecting the Network.	Extreme	Medium
11	⬇ (10)	Failure of a retailer, customer, supplier or contractor to perform their contracted obligations, including financial obligations.	Extreme	Medium
12	⬇ (11)	Taxation authorities dispute Business' position on tax treatments.	Extreme	Medium
13	⬇ (12)	Non compliance with relevant laws, regulations and reporting requirements.	Extreme	Medium
14	⬇ (13)	A prolonged interruption to the voice and data communications network.	Extreme	Medium
15	⬆ (27)	Non-optimisation of regulated returns within a regulatory period.	High	Medium

Figure 5-7 Summary of Top 15 Business Risks

Two changes in the top five in the table above are:

- The movement up four places of "a loss of connection supply from transmission assets" and a residual rating of High following learnings from the Penrose substation fire in Auckland; and
- The introduction of a new risk rated as High relating to IT security.

The business identified 183 unique controls that aim to mitigate the causes and consequences across the identified risks. The following table indicates the top 15 controls for managing risk across the business.

Ranking	Control Name
1	Work Type Competency
2	Asset Management Policies, Strategies, Standards and Plans
3	Site Specific Risk Plans
4	Contractor Management System and Processes
5	Insurance
6	Design and Construction Policies and Procedures
7	Health and Safety policies and procedures
8	Contract Management and Documentation
9	Crisis & Emergency Management
10	Incident Reporting & Investigation processes and standards
11	Purchasing and Procurement Policy and Processes
12	Network Contingency Plans
13	Asset Failure Investigation Process
14	Contractor Compliance Audits
15	Operational Processes and Procedures

Figure 5-8 Summary of Top 15 Risk Controls

Controls are ranked across the business by a control criticality rating, which takes into account:

- The number of risks associated with each control;
- A risk control score (the difference between the inherent and residual risk ratings); and
- Confidence and reliance ratings for the control.

Many of the controls listed in Figure 5-8 are described in different sections of this document (for example Asset Management Policies and Strategies are described in Section 3). Insurance as a Risk control is described in 5.2.3.1.

5.2.3.1 Insurance Cover

Wellington Electricity renews its insurances in two tranches.

1. Industrial Special Risks (ISR) Insurance, which includes Material Damage and Business Interruption cover and is renewed annually as at 30 June; and

2. General Products and Liability Insurance, includes general, products, pollution, electro-magnetic radiation, financial loss (failure to supply), and professional indemnity and is renewed annually as at 30 September.

While the global market for insurance has recovered following the massive losses from the significant natural events of 2011 and 2012, the global insurance industry has adopted a strict technical approach to rating and retention levels in an attempt to recover previous losses.

In 2015 Wellington Electricity commissioned an updated GNS Science (GNS) report to assist in quantifying its insurance risk and requirements and to help mitigate insurance premium increases. GNS estimated losses to insured assets from potential earthquake and tsunami events. This report estimated losses to insured assets were within existing insurance limits.

Wellington Electricity will continue to work with the wider CKI and Power Assets group to obtain market competitive insurance premiums by accessing international market opportunities that would be difficult to achieve on a standalone basis in New Zealand. Whilst obtaining insurance capacity for Wellington-based risks continues to be a challenge, Wellington Electricity has engaged other markets, notably the Australian, Singapore and London markets, to ensure competitive insurance cover is maintained.

5.2.3.2 Insurable Risks and Increased Insurance Premiums

Wellington Electricity insures around 15% of the estimated asset replacement cost of network assets, covering key strategic assets. The level of insurance cover purchased is based on estimates by GNS to determine maximum foreseeable loss for assets that can reasonably be insured.

The balance (85% by replacement value) of Wellington Electricity’s network is not insured, because insurance cover is not available or economically viable. As such, the business retains the risk on the uninsured portion of the network even though the regulated line charges do not include an allowance for the recovery of the cost of retaining the risk. Wellington Electricity does not insure its subtransmission and distribution assets (lines and cables), as insurance cover for these types of assets (poles, cables, wires etc.) is currently only available from a small number of global reinsurers, is very expensive, has high deductibles, and typically excludes damage from windstorm events. Since such costs are not passed on to consumers in the line charges, it is not an economic proposition for the company to obtain such insurance.

Illustrating this by way of example, if Wellington Electricity were to insure poles, cables and wire assets with a policy limit of $500 million, it would need to pay a 10% deductible of $50 million before any insurance payments would be provided. In addition the annual insurance premium for such cover would be in the $40 million to $50 million range.

Ex post recovery of the full costs is therefore the expected regulatory recovery mechanism for managing this risk.

Wellington Electricity would likely seek to recover the fair and reasonable cost for restoring power supplies following a major natural disaster such as a significant earthquake, from consumers in a similar way that Orion did following the 2010 and 2011 Canterbury earthquakes.

5.3 Asset Management Framework

The asset management framework which Wellington Electricity operates to is aligned with the company's mission and objectives and is reflected in this AMP. The framework reflects the principles of the international standard ISO 55000. The key components of the framework are the asset management policy, strategies, investments plans and delivery phase as shown in Figure 5-9.

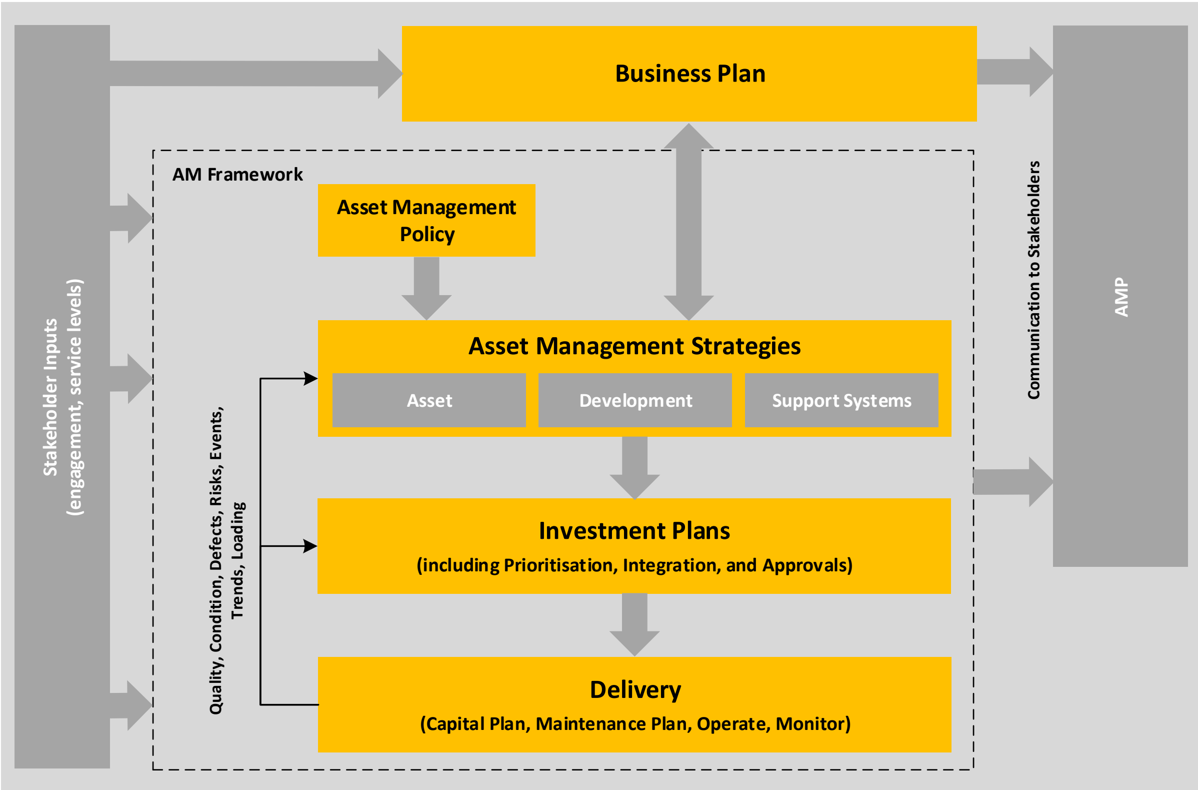


Figure 5-9 – Asset Management Framework

Each component of the Asset Management Framework is described below.

5.3.1 Asset Management Policy

The asset management policy establishes the formal authority for asset management within Wellington Electricity. The asset management policy has the following objective that the business will:

> *"Optimise the whole of life costs and the performance of the distribution assets to deliver a safe, cost effective, high quality service to our customers."*

The policy also states that Wellington Electricity's electricity network shall be designed, constructed, operated and maintained in a safe and efficient manner which:

- Has a strong safety focus regarding its employees, contractors and members of the public;
- Aligns with corporate objectives and plans;
- Is founded on customer service level expectations and engages stakeholders where appropriate on asset-related activities;

- Stays up to date with national and international asset management standards, trends and best practices;
- Complies with all applicable regulatory and statutory requirements;
- Accords with the risk management framework;
- Aligns with staff capabilities and external resources when required; and
- Provides a suitable long-term return on investment for shareholders.

5.3.2 Asset Management Strategies

The asset management strategies developed by Wellington Electricity have been established to deliver the service levels described in Section 4.

Wellington Electricity separates out network strategy and associated objectives into three main categories:

1. Fleet strategies focusing on operating, maintaining, replacing and disposal of existing network assets, including resilience expenditure associated with Wellington Electricity's existing network infrastructure. These are discussed in Section 6;
2. Network development strategies dealing with the changing consumer demand, any new developments, and impact of emerging technologies. These are discussed in Section 7; and
3. Support System Strategies focusing on the replacing, maintaining, and operating the IT support systems and other requirements for running Wellington Electricity's business operations. These are discussed in Section 8.

5.4 Investment Plans

Development of investment plans follows five generalised stages as illustrated in Figure 5-10. The five stages are identification of investment need, identification of options, selection of the most appropriate option, approval, and delivery.

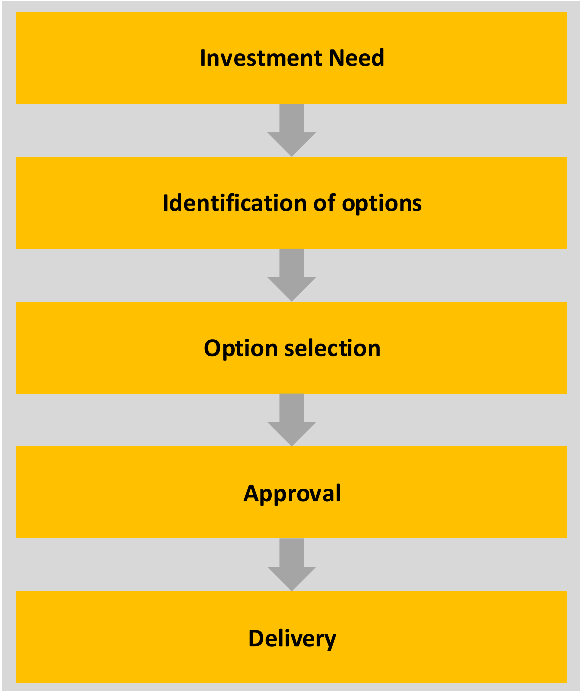


Figure 5-10 – Investment Plan Process

5.4.1 Need Identification

The identification of investment need arises from multiple sources. For example, fleet strategies for asset replacements arise from asset condition assessment and detailed health indices evaluation, whereas the need for network development expenditure comes from forecasting of peak load growth on the network and developers extending their subdivision or commercial investments.

5.4.1.1 Risk-based Approach

Wellington Electricity takes a risk-based approach to need identification. Management of risk is fundamental to network development, asset maintenance, refurbishment and replacement programmes described in this AMP. Risks associated with network assets are managed:

- Proactively: Reducing the probability of asset failure through safety-by-design principles, meeting security of supply criteria standards, capital and maintenance work programmes, insurance strategies and enhanced working practices; and

- Reactively: Reducing the impact of a failure through business continuity planning and the development of an efficient fault response capability.

The risk of an asset failure is a combination of the likelihood of failure (largely determined by the condition of the asset) and the consequences of failure (determined by the magnitude of any supply interruptions, the repair or replacement time and the extent of any reduction in network operating security while the asset is being repaired). Assessment of this risk assists the process of deciding whether to phase out an asset through a planned replacement programme or allow it to continue in service, supported if necessary by additional inspection and preventative maintenance activity. The risks associated with each asset fleet and network area are discussed further in Sections 6, 7 and 8.

5.4.1.2 Prioritisation of Projects

The asset management plan represents the view for the next 10 years and is refined on an annual basis. Projects to be included in the expenditure programme for a year are subject to a top down review and prioritised in accordance with the sequence shown below.

- Safety benefits to the public and personnel;
- Non-discretionary projects;
- Commercial returns and investment recovery;
- Quality of supply and stakeholder satisfaction;
- Risk to the network; and
- Strategic benefit.

A subset of non-discretionary projects outside of the prioritisation process includes:

(i) HSE and Legal Compliance

Wellington Electricity's top priority is to operate a safe and reliable network and thus projects needed to address safety concerns and/or meet legal requirements are given high priority.

(ii) Customer-initiated Projects

Provided Wellington Electricity has received sufficient advanced notice, it will give appropriate priority to planning, designing and implementing projects required to meet the needs of commercial and industrial customers.

Under this approach, safety, legal compliance, the need to meet customer requirements, and risk mitigation are the critical elements that drive the inclusion of projects in the works programme.

5.4.2 Option Identification

Following need identification, various options are identified to meet the investment need. These include:

- Non-network solutions such as demand-side-management or distributed generation (DG). These could include investment by the consumer in the case of residential/commercial solar PV (or other forms of DG), or by Wellington Electricity in the case of grid-scale PV and/or battery storage;
- An extension or upgrade of the existing distribution network;
- Repair or refurbishment of existing distribution assets; and
- Replacement with new assets.

These investment needs are considered to ensure that overall service levels sought by stakeholders are achieved within allowances. This is to align the reliability with cost the customers pay over the long term.

5.4.3 Option Selection Process

The option selection process describes the way in which network investments are taken from a high level need through to a preferred investment option that in turn is supported by a business case or project recommendation. It includes consideration of a list of appropriate options, refinement of the list to a short list of practicable options followed by detailed analysis and selection of a preferred option. The Works Plan is the repository for all potential network investments for the year ahead and includes projects funded solely by Wellington Electricity as well as other customer-funded projects. The Works Plan is consistent with the first year of the AMP. Changes to either plan are required as an input to the other plan (i.e. AMP changes that impact the order of work in the next 10 years will be factored into the next Works Plan prepared).

The process is as follows:

1. Outputs from the option identification process are developed into a project recommendation, justifying the need for investment and recommending the preferred option.

2. Approved recommendations are entered into the Works Plan and prioritised in terms of budget, timelines and network criticality. Customer connection requests are also recorded in the Works Plan.

3. Following final prioritisation and budget confirmation, a list of projects for the following year (i.e. the Works Plan) is prepared for management approval and recommendation to the Board for approval as part of the annual budget.

5.4.4 Investment Approval

Investments are approved according to Wellington Electricity's DFA structure. This is described within Section 3.2.3.

5.5 Asset Management Delivery

The Works Plan is the repository for all potential network investments for the year ahead. It is utilised as the final document for tracking all network capital projects to be delivered for the year. Once approved, the Works Plan is managed by Service Delivery team.

5.5.1 Field Delivery

Wellington Electricity utilises an outsourcing model for the delivery of its field and construction work. The service providers used for the core field and network functions are:

- Fault response, maintenance, and minor capital works – Northpower;
- Contestable capital works – Northpower, Downer and Connetics;
- Vegetation management – Treescape; and
- Contact centre – Telnet.

All outsourced agreements are subject Wellington Electricity's health and safety policies and management plan. It is the responsibility of the GM – Service Delivery to ensure this and that all field based work is managed to deliver value to the business.

The services provided are described in further detail below.

Fault Response, maintenance and minor capital works - Northpower

Since 2011, Northpower Ltd has been Wellington Electricity's primary field service provider responsible for fault response and maintenance. During 2015, Wellington Electricity completed a process of negotiating a new Field Services Agreement (FSA) with Northpower for a further three years, effective from January 2016.

The FSA with Northpower delivers a number of strategic outcomes for Wellington Electricity. It is structured to ensure alignment with Wellington Electricity's asset management objectives and to improve the integrity of the asset data held in Wellington Electricity's information systems. The FSA covers the following services:

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

The FSA includes key result areas (KRAs) and performance targets that Northpower is required to meet, with incentives for high levels of achievement. The cost of work undertaken is based on commercially tendered unit rates. The FSA is managed with a series of monthly meetings to cover off key functional areas between Wellington Electricity and Northpower.

Contestable Capital Works Projects (Northpower, Downer and Connetics)

Contestable capital works include:

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

Contestable capital works projects are generally competitively tendered. They are delivered under either independent contractor agreements or the FSA if Northpower is the successful tenderer. These agreements outline the terms and performance requirements the work is to be completed under such as KPIs or KRAs, defects liability periods, and insurance and liability provisions to limit the exposure of Wellington Electricity. All contracts are managed on an individual basis, and include structured reporting and close out processes including field auditing during the course of the works.

In some instances, low value works or in circumstances where only one supplier can provide the required service, projects are sole sourced. In the case of sole source supply, pricing is benchmarked against comparable market data. Under the project management framework, work scopes are defined and there are stringent controls in place for variations to fixed price work.

Vegetation Management (Treescape)

This outsourced contract is in the process of being renewed with Treescape. The revised contract provides for vegetation management as per the Tree Regulations, as well as improved landowner awareness of tree hazards.

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

Contact Centre (Telnet)

The Contact Centre provides management of consumer and retailer service requests, outage notification to retailers and handling general enquiries. Management of this contract is the responsibility of the Chief Financial Officer.

5.6 Asset Management Documentation and Control

Wellington Electricity has a range of documents relating to asset management. These documents include:

- High level policy documents – which define how the company will approach the management of its assets;
- Asset fleet strategies - asset maintenance, lifecycle management and renewal strategies for a range of asset groups, from subtransmission cables and power transformers to the various pole types and LV installations;
- Network development plans - providing a 15 year plan of forecasted load growth, potential constraints and strategies to mitigate in conjunction with asset renewal and reliability improvement programmes;
- Technical standards for procurement, construction, maintenance and operation of network assets;
- Network guidelines - provide directions and procedures on the construction, maintenance and operation of network assets and processes to achieve a desired outcome; and
- Network instructions - provide further instructions on the construction, maintenance and operation of network assets and processes.

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.

5.6.1.1 Controlled Document Process

A large number of standards relating to network materials, construction (including standard drawings) and operational standards have been updated or developed and approved through the Controlled Document Process. This work will continue in 2016 and future years.

The Controlled Document Process ensures that new or altered documents are released to staff and contractors in a controlled manner. 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 deliver 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.

5.7 Asset Management Maturity Assessment Tool (AMMAT)

The Asset Management Maturity Assessment Tool (AMMAT) is provided in Appendix D, 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 graph in Figure 5-11, extracted from the AMMAT, gives a summary of the results.

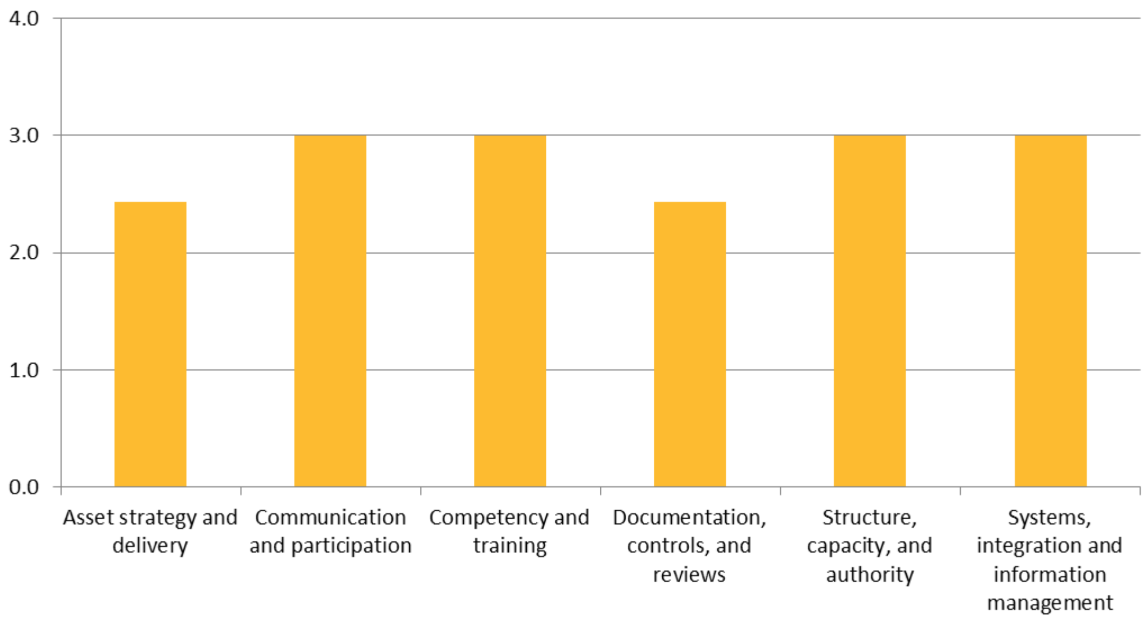


Figure 5-11 Summary of the AMMAT Assessment 2016

The areas identified in the AMMAT to be lower than Maturity Level 3, and a brief description of the development strategy to get from the present maturity level to Level 3 is provided in Figure 5-12. Development of areas 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	Development Strategy
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?	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined. The work is fairly well advanced but still incomplete	Development of long-term strategies for all remaining asset categories will continue during 2016
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 long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems	As per question 10 above, development of lifecycle asset management strategies will continue during 2016
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 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	As per question 10 above, development of lifecycle asset management strategies will continue during 2016
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	An overview document of the asset management system needs to be developed.
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 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	Through the development of the lifecycle asset strategies for all categories, a summary of all asset related risks can be compiled and provided in future plans where appropriate
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 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 forms part of the asset strategies currently in development.
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	Extend audit regime to cover identified areas of the asset management process which are not presently covered.

No	Function	Question	Maturity Level Comment	Development Strategy
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	Review of the effectiveness of the newly developed asset strategies identified above. Provision of feedback into the strategy documents to ensure effectiveness.

Figure 5-12 Strategies for Improving Asset Management Maturity

5.8 High Impact Low Probability (HILP) Events

Wellington Electricity's network is designed with a certain amount of resilience to a level of adverse events. However, like all EDBs, the network is susceptible to potential HILP events, which could cause a major unplanned outage for a prolonged period of time. Due to its geographical location, the HILP events that Wellington Electricity is particularly vulnerable to are a major earthquake, tsunami or windstorm. Other possible HILP events include upstream supply failure, communications failure, or information security breach or loss.

Significant HILP events are unpredictable, often uncontrollable, and incredibly expensive to avoid, if at all possible. Wellington Electricity plans for HILP events to mitigate the impact as best as it can. HILP risks are managed through a combination of Wellington Electricity's network planning and design, asset maintenance, fault response and emergency response strategies. In addition, Wellington Electricity's design standards are aligned with industry best practice. The design standards take account of the weather and the seismic environment in the greater 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.

5.8.1.1 Identification and Management of HILP Events

Wellington Electricity identifies HILP events through some of the following methods:

- Transmission risk reviews – participation in the Connection Asset Risk Review project undertaken by Transpower. (This was a HILP study for the Wellington CBD to identify risks on the transmission circuits and substations, and to develop mitigation measures);
- Distribution risk reviews – as part of the network planning process, HILP events are identified. Examples of such events include the simultaneous loss of subtransmission circuits causing a complete loss of supply to a zone substation, or the destruction of a zone substation. Contingency plans have been drawn up to mitigate such events, and
- Environmental risk reviews – understanding and identification of the risk posed by natural disasters such as earthquake and tsunami. Studies are undertaken on behalf of Wellington Electricity by GNS and other external providers.

5.8.1.2 Strategies to manage HILP events

Wellington Electricity applies the following strategies to manage HILP events as well as drawing on the experience of others (such as learnings from Orion following the Canterbury earthquakes):

- Identification – understand the type and impact of HILP events that the network may experience;

- Reduction – minimise the consequence of the HILP event through investment in resilience;
- Readiness – reduce the impact of an HILP event where appropriate, by improving network resilience;
- Response – develop plans to respond to HILP events in terms of business processes; and
- Recovery – including the use of contingency plans to invoke a staged and controlled restoration of network assets and supply capability.

The management of HILP event are addressed in a number of plans and initiatives across the business described in the following section.

5.9 Emergency Response Plans and Contingency Planning

Wellington Electricity has emergency response procedures, contingency plans and critical emergency spares in place to mitigate and manage the impact of a HILP event. These are discussed below.

5.9.1 Wellington Lifelines Group (WeLG)

The Civil Defence and Emergency Management (CDEM) Act 2002 stipulates the responsibilities and roles of key organisations that provide an essential service within New Zealand. Wellington Electricity's core business of electricity distribution is an essential service and under the CDEM Act it has been classified as a Lifeline Utility. As such, Wellington Electricity must:

- Ensure that it is able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency;
- Have a plan for functioning during and after an emergency;
- Participate in CDEM strategic planning; and
- Provide technical advice on CDEM when required.

The CDEM Act 2002 places an emphasis on ensuring that lifeline utilities provide continuity of operation, particularly where their service supports essential CDEM activity.

Wellington Electricity belongs to the WeLG that focuses on pre-event planning, and its primary purpose is to:

"co-ordinate the physical risk management activities of Wellington utility and transport service providers in relation to regional scale events that affect a number of interdependent organisations".

WeLG comprises of lifelines utility owners that operate in the Wellington region, including the local authorities, crown entities (such as NZTA) and private companies (such as telecommunications companies) to identify and prepare contingency plans for the region following a major disaster. As part of its WeLG group participation, Wellington Electricity is involved with the Wellington Region Emergency Management Office, which is a joint council organisation providing civil defence functions to the region.

5.9.2 Emergency Response Plans (ERPs)

As part of the Business Continuity Framework Policy, Wellington Electricity has a number of ERPs to cover emergency and high business impact situations. The ERPs require annual simulation exercises to test the plans and procedures and provide feedback on potential areas of improvement. All ERPs are periodically reviewed and revised. Learnings from natural disasters in New Zealand such as the Christchurch earthquakes and the Wellington June 2013 storm have been incorporated into these plans.

5.9.3 Civil Defence and Emergency Management (CDEM) Plan

Wellington Electricity has prepared the CDEM Plan to comply with the relevant provisions of the CDEM Act 2002. It provides information for the initiation of measures for saving life, relieving distress and restoring electricity supply.

This CDEM Plan follows the four 'Rs' approach to dealing with hazards that could give rise to a civil defence 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; and
- Recovery - rehabilitating and restoring to pre-disaster conditions.

5.9.4 Crisis Management Plan (CMP)

The CMP defines the structure of the Crisis Management Team and the roles and responsibilities of staff during a crisis. The CMP contains detailed contact lists of all key stakeholders who may contribute to, or be affected by, the crisis.

5.9.5 Major Event Management Plan (MEMP)

The MEMP defines a major event and describes the actions required and the roles and responsibilities of staff during a major event. A focus of the MEMP is how the internal and external communications are managed. It contains detailed contact lists of all key stakeholders who may contribute to, or be affected by, the major event. Should the event escalate to a crisis, it is then managed in accordance with the CMP.

5.9.6 Business Recovery Management Plan (BRMP)

The BRMP covers, any event that interrupts the occupancy of Wellington Electricity's 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. This site has meeting and office spaces, as well as functional SCADA terminals and communications equipment, along with the necessary IT equipment, to allow network operations to continue with only a short interruption. Several other key business processes can also be operated from this site should the Petone corporate offices be unavailable.

5.9.7 Information Technology Recovery Plan (ITRP)

The ITRP is in place so that Wellington Electricity's IT systems can be restored quickly following a major business interruption affecting these systems. The level of recovery has been determined based on the business requirements.

5.9.8 Major Event Field Response Plan (MEFRP)

The MEFRP covers Wellington Electricity's field contractors so they are prepared for, and can respond appropriately to, a HILP event. The MEFRP designates actions required and responsibilities of Wellington Electricity and field contractor coordination during an event. It focuses on systems and communications (internal and external) to restore supply. A major event field response can escalate to the MEMP if required.

5.9.9 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.

5.9.10 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;
- Creating a safe working environment; and
- Maintaining 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.

5.9.11 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;
- Network Spares Management Policy
- 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); and
- Call Centre Continuance Plan.

In addition, contingency plans are prepared as necessary detailing special arrangements for major or key customers.

5.9.12 Seismic Reinforcing of Equipment and Buildings

Following changes to the Building Code post the Christchurch earthquakes, a number of Wellington Electricity's substation buildings require reinforcement to ensure they comply with the minimum standards set by local authorities. As a result Wellington Electricity has been surveying and identifying potential seismic issues concerning the assets in network buildings. Major equipment within zone substations, such as transformers, switchgear, service transformers and battery stands, has been seismically restrained. Heavy loose equipment has been removed from substations and relocated to a centralised store.

Wellington Electricity's Substation Building Seismic Policy includes the following key elements:

- Network substations must provide a satisfactory level of resilience against major seismic activity;
- Timely restoration of power is required following a disaster;
- To have no buildings which are earthquake-prone following an assessment and the necessary remedial works; and
- Wellington Electricity-owned buildings should not fail in a way that endangers the safety and property of its personnel or members of the public.

A key target from the policy is to have all substation buildings constructed prior to 1976 (when significant changes were made to design requirements) subjected to an independent seismic assessment within three years. Each building is evaluated using the Initial Evaluation Process (IEP) as set out in the NZ Society for Earthquake Engineering Recommendations for the Assessment of the Structural Performance of Buildings in an earthquake. Changes under the Building Act of 2004 require older buildings to have the performance capacity of at least one third of the New Building Standard (NBS), and a building with a seismic strength calculated < 34% is categorised as 'earthquake prone'.

Wellington Electricity has nearly 500 substation buildings with the age profile shown in Figure 5-13.

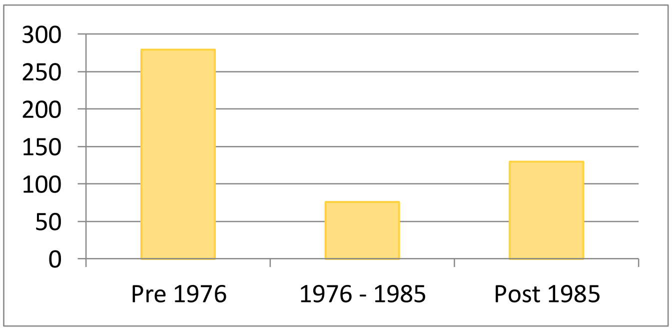


Figure 5-13 Substation Buildings Age Profile

328 substation buildings were identified as needing to be assessed. These include all 279 substation buildings constructed prior to 1976, all zone substation buildings and all key distribution substation buildings.

Local councils also conduct assessments of selected buildings within their region to ensure compliance with their earthquake prone buildings policies.

Wellington Electricity used independent local structural consultants to undertake the IEPs and subsequent Detailed Seismic Assessments (DSAs). Figure 5-14 shows the status and local authority location of the assessed buildings.

Building Status	Wellington City Council	Lower Hutt City Council	Upper Hutt City Council	Porirua City Council	Total
Confirmed not earthquake prone	176	47	14	19	**256**
Confirmed Earthquake prone by DSAs	9	5	0	3	**17**
Indicated as Earthquake prone by IEPs	24	6	0	0	**30**
IEPs Completed but no percentage NBS yet assigned	16	5	2	2	**25**
Total	225	63	16	24	**328**

Figure 5-14 Building Assessment Status

The consultants have assessed 47 buildings as being confirmed or suspected to be earthquake prone. The initial 17 had DSAs completed and strengthening costs estimated. The details of these are shown in Section 6. The strengthening work undertaken is designed to achieve effective reinforcement to minimise the risk to public, personnel and to the electrical plant within the building.

The first building to be seismically strengthened post the Christchurch earthquakes was the Adelaide Road substation in 2014. Some of the reinforcement work can be seen in Figure 5-15.

Figure 5-15 Seismic Strengthening at Adelaide Road Substation

An additional three substation buildings (176 Wakefield Street, Riddiford Street, and Moana Road) were strengthened during the last quarter of 2015 and the first quarter of 2016 at a cost of approximately $250,000. The remaining 14 confirmed sites that require seismic upgrades during the planning period are shown in Section 6.

5.9.12.1 Changes to Earthquake-prone Buildings Policy

In May 2015, the Government announced it had revised its policy on earthquake-prone buildings in favour of a more targeted approach that focuses on the buildings which pose the greatest risk to life. It ensures the response is proportionate to the risk, that the costs are minimised and that New Zealand retains as much built heritage as possible.

The main changes include:

- Varying the timeframes for identifying and strengthening earthquake-prone buildings according to the seismic risk around New Zealand (with timeframes for identifying potentially earthquake-prone buildings of five, 10 and 15 years, and timeframes for strengthening earthquake-prone buildings of 15, 25 and 35 years – timeframes dependant on the seismic risk of the area);

- Reducing the scope of buildings covered by the system – excluding farm buildings, retaining walls, fences, monuments that cannot be entered (e.g. statues), wharves, bridges, tunnels and storage tanks;

- Prioritising education buildings, emergency service facilities, hospital buildings and corridor buildings by requiring that in high and medium seismic risk areas they be identified and strengthened in half the standard time;

- Introducing new measures to encourage earlier upgrades through a new requirement to strengthen earthquake-prone buildings when substantial alterations are undertaken; and

- A more focused Earthquake-prone Buildings Register and enhanced public notices on earthquake-prone buildings that give information about the earthquake rating of the building.

The Building (Earthquake-prone Buildings) Amendment Bill is currently being considered by the Local Government and Environment Select Committee.

For Wellington Electricity, the total cost of this work is expected to be approximately $7 million. Under the 2014 DPP decision, additional resilience expenditure was not included in the allowances set by the Commission, as Wellington Electricity was the only distributor to ask for an increase for resilience expenditure. As a result, the current programme of substation building reinforcement has been included in the plan as a prolonged programme, limiting the investment made in any one year whilst keeping within the remediation timeframes required by legislation. Further details on how Wellington Electricity is proposing to stage this expenditure is described in Section 6.

5.9.13 Transpower Risk Review and Plan for Central Park

The majority of load within the Wellington CBD is currently supplied from Central Park. A catastrophic failure at this station will result in an outage to over 55,000 customers including a number of critical services such as:

- Wellington Hospital and a number of private hospitals;

- Water treatment and pumping stations;

- Parliament and civil defence facilities;

- Traffic lights, trolley bus supply and street lighting;

- The stock exchange, Treasury, banking, and financial institutions; and
- Data centres and customers with sensitive load requirements.

The following issues at Central Park are considered HILP events by Wellington Electricity:

- The configuration of the 33kV switchroom presents a substantial single point failure risk as there is no active fire suppression installed. Additionally, there is no segregation or blast wall between the individual 33kV bus sections, and all 33kV cabling is installed in a common trench prior to termination to the switchgear;
- The circuits supplying transformers T4 and T5 share a common structure for the entire route between Wilton and Central Park. Additionally, all three 110kV lines are installed on common structures for a portion of the route prior to entry to Central Park. A failure of these structures will completely interrupt supply to Central Park;
- There is minimal segregation between transformers T3 and T4 and a lack of blast protection. Catastrophic failure of one of these units has the potential to damage the adjacent unit, potentially reducing the supply capacity to a single transformer for a potentially lengthy duration for repair and restoration works. Transpower is looking at both short and long term options to install a firewall between T3 and T4; and
- Catastrophic failure of the Wilton 110kV bus will result in a loss of supply to all customers in the Southern area for a substantial duration including Central Park. Work is currently underway rebuilding the 110kV bus as a three-section bus. This will adequately address the supply diversity concerns at Wilton as each of the three Central Park circuits will be terminated to an individual bus section.

Wellington Electricity and Transpower have agreed a set of additional controls to be implemented at Central Park in 2016.

5.9.14 33kV Emergency Overhead Lines

Underground subtransmission cables utilising gas- and oil-filled technologies can be vulnerable to seismic events. Repairs to extensively damaged gas- and oil-filled cables could take a number of months, which is unacceptable if the repair is necessary to restore supply. There are over 50,000 consumers supplied from zone substations with gas and oil subtransmission cables which are vulnerable to earthquakes. Wellington Electricity has engaged with Wellington City Council to specifically address this issue and to develop the protocols for the emergency installation of overhead 33kV lines should supply become unavailable for an extended period following a major event.

Wellington Electricity engaged a line design consultant to carry out route planning and line design for emergency 33kV overhead lines to supply CBD zone substations from Transpower GXPs. The selection of the proposed routes considers all risks within their immediate vicinity such as earthquake prone buildings, vegetation, topography, ground conditions and ease of access for construction.

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 remaining zone substations outside the Wellington City area is underway and will be completed over the period 2016 to 2017. 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.

Prototypes of the surface foundation structures have been fabricated and tested. Design improvements will be implemented during 2016 and a quantity will be manufactured and held at various locations around the Wellington area, along with other components such as poles, pole hardware and conductors.

5.9.15 Resiliency Project 2016

During 2016 Wellington Electricity will further develop a business case assessing options to improve the overall resiliency of the network for HILP events (such as a major earthquake). This work will involve consultation with key customers as well as other utilities supplying the Wellington region, recognising the interdependencies between electricity supply and other infrastructure providers such as water and roading. This plan will also consider the additional costs of procuring hardware for emergency corridors. Undertaking this work would require funding above the 2015-20 DPP allowances.

Section 6:

Asset Lifecycle Management

6 Asset Lifecycle Management

This section provides an overview of Wellington Electricity's assets, and their maintenance, refurbishment and replacement strategies over the planning period. The objective of these strategies is to optimise operational, replacement and renewal capital expenditure on network assets, whilst ensuring that the network is capable of meeting the service level targets and mitigating risks inherent in running an electricity distribution network.

In summary, the section covers:

- Asset fleet summary;
- Risk-based asset lifecycle planning;
- Stage-of-life and asset health analysis;
- Maintenance practices;
- Asset maintenance and renewal programmes;
- Building resilience expenditure; and
- Asset replacement and renewal summary.

6.1 Asset Fleet Summary

A summary of the population for each asset class is shown in Figure 6-1.

Asset Class	Section	Measurement Unit	Quantity
Subtransmission Cables	6.5.1	km	137
Subtransmission Lines	6.5.3.2	km	58
Zone Substation Transformers	6.5.2.1	number	52
Zone Substation Circuit Breakers	6.5.2.2	number	369
Zone Substation Buildings	6.5.2.3	number	27
Distribution and LV Lines	6.5.3.3	km	1,685
Streetlight Lines	6.5.3.3	km	809
Distribution and LV Poles	6.5.3.1	number	36,694
Distribution and LV Cables	6.5.4	km	2,819
Streetlight Cables	6.5.4	km	1,087
Distribution Transformers	6.5.5.1	number	4,348
Distribution Substations	6.5.5.1	number	3,616

Asset Class	Section	Measurement Unit	Quantity
Distribution Circuit Breakers	6.5.5.2	number	1,296
Distribution Reclosers	6.5.6.1	number	18
Distribution Switchgear - Overhead	6.5.6.2	number	2,603
Distribution Switchgear - Ground Mounted	6.5.5.2	number	2,265
Low Voltage Pits and Pillars	6.5.5.3	number	16,857
Protection Relays	6.5.7.2	number	1,361
Load Control Plant	6.5.8.3	number	26

Figure 6-1 Asset Population Summary

6.2 Risk-Based Asset Lifecycle Planning

Risk-based asset lifecycle planning consists of the following:

- Design, construction and commissioning according to network standards, including the use of standardised designs and equipment where appropriate;
- Condition based risk assessments;
- Routine asset inspections, condition assessments and servicing of in-service assets;
- Evaluation of the inspection results in terms of meeting customer service levels, performance expectations and control of risks;
- Maintenance requirements and equipment specifications to address known issues; and
- Repair, refurbishment or replacement of assets when required.

Throughout all of these stages, ensuring the safety of the public and workers is the highest priority.

Wellington Electricity takes a risk-based approach to asset lifecycle planning. The preventative maintenance programme is time-based, with each maintenance task having a set cycle based on a known reliability history or condition degradation trend. Corrective maintenance tasks identified as a result of preventative maintenance are prioritised for repair according to severity and consequential risk to safety and network performance.

Standardised designs are used for high volume assets, including overhead and underground construction at 11kV and 400V, distribution substations, and distribution switchgear. This approach ensures:

- Familiarity for contractors, increasing the safety and efficiency of construction and operation;
- Procurement benefits, through reduced lead times and increased stock availability; and
- Economic benefits, as standard products generally have lower cost than customised or non-standard ones.

High value asset replacements such as subtransmission cables and zone substation assets are designed to meet the specific needs of the project, however must still meet the requirements of relevant network standards.

Electricity distribution assets have a long but finite life expectancy and eventually require replacement. Premature asset replacement is costly as the service potential of the replaced asset is not fully utilised. Equally, replacing assets too late can increase the risk of safety incidences and service interruptions for customers. Asset replacement planning therefore 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 critical assets are allowed to fail in service. Hence, there is a balance to be found between the cost of maintaining an asset in service and the cost to replace it.

This section focuses on the different asset classes and provides an insight into the condition and maintenance of each class with an overview of maintenance programmes and renewal and refurbishment programmes.

6.3 Stage of Life and Asset Health Analysis

Prior to 2015, Wellington Electricity used a Stage of Life analysis to prioritise major asset replacement. Stage of Life gave weightings to asset age and a number of factors influencing condition and utilisation to provide an overall score for each asset, which could then be ranked to give a priority.

In practice, Stage of Life was very sensitive to the weightings given to each attribute and the method of normalisation meant that scores were not comparable across different asset classes. However, the analysis did provide a useful means of highlighting which assets within a class required closer attention.

During 2014, the Electricity Engineers Association released their draft guide to Asset Health Indicators[17]. This method specifies a number of health indices for each asset class, which are rated on a scale of H5 (new) to H1 (end of life). The overall asset health indicator (AHI) is determined by its worst health index, further reduced by any indices scoring less than H4.

Asset Health Analysis offers a number of advantages over Stage of Life, particularly in that it does not rely on factors having subjective weightings. However, unlike Stage of Life, Asset Health Analysis does not take any account of asset criticality or consequence of failure. Wellington Electricity has developed an Asset Criticality Indicator (ACI) using the same methodology as Asset Health Analysis, incorporating factors such as number of customers affected, load type and firm capacity. Asset Criticality is scored on a scale of I5 (very low impact) to I1 (major impact).

The result of this analysis is a health-criticality matrix for each major asset class, with the asset location on the matrix giving an indication of risk. As an example, the health-criticality matrix for power transformers on the Wellington Electricity network is shown in Figure 6-2 and further discussed in Section 6.5.2.

[17] "EEA Asset Health Indicators Consultation Draft", May 2014

		Lowest Impact		Asset Criticality			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				1			
	1.5				1			
Asset Health	2.0				1			
	2.5			2	10		2	
	3.0			4	15		2	1
	4.0			2	6		2	3
Best Health	5.0							

Figure 6-2 Example Health-Criticality Matrix

Each number in the matrix gives the number of assets, be they units or circuits, falling into that particular combination of health and criticality. The highest priority is to address assets in the red area of the matrix. These require work to move them to a lower priority colour. Orange assets are the next priority, and should have work undertaken to move them to a lower priority. Yellow assets are candidates for additional monitoring, maintenance or contingency planning, due to either their health being marginal or their criticality being high. Green assets can continue operating with normal routine maintenance as identified in Wellington Electricity's maintenance practices.

Projects are identified to either improve the health of an asset, or reduce its criticality. The impact of potential changes to health and/or criticality, whether the result of a project or deterioration in condition, can be clearly shown by the movement of the asset within the matrix.

Accordingly, Wellington Electricity is progressively moving the assessment of asset fleets to the risk based asset health-criticality framework to provide an objective and prioritised list of needs to be addressed within the planning period. To date the asset classes that have been addressed are:

- Subtransmission cables;
- Zone substation power transformers and tap changers;
- Zone substation switchboards and circuit breakers;
- Poles;
- Distribution transformers, and
- Ground-mounted distribution switchgear.

6.4 Maintenance Practices

6.4.1 Maintenance Standards

Wellington Electricity currently contracts Northpower as its Field Services Provider to undertake the network maintenance programme under a Field Services Agreement. Maintenance of all assets is undertaken according to standards that have been developed by Wellington Electricity.

Condition-based risk management of assets is achieved through a well-defined condition assessment and defect identification process that is applied during planned inspection and maintenance activities. The condition information is then fed into the SAP PM maintenance management system by the Field Services Provider and analysed alongside other key network information. This enables Wellington Electricity to prioritise field data to make efficient and optimised asset replacement decisions and maintain visibility and tracking of maintenance tasks in the field.

Vegetation management is provided by Treescape and is carried out in accordance with Wellington Electricity policies and the Electricity (Hazards from Trees) Regulations 2003. Under the regulations, tree owners are responsible for maintaining their vegetation to a safe clearance distance. There is a risk that this maintenance does 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 becomes resource intensive.

6.4.2 Maintenance Categories

Maintenance is categorised into the following areas:

1. **Service Interruptions and Emergencies.** Work that is undertaken in response to faults or third party incidents and includes equipment repairs following failure or damage, and the contractor management overhead involved in holding resources to ensure appropriate response to faults.

2. **Vegetation Management.** Planned and reactive vegetation work.

3. **Routine and Corrective Maintenance and Inspection.** This comprises:

    a. **Preventative Maintenance works.** Routine inspections and maintenance, condition assessment and servicing work undertaken on the network. The results of planned inspections, and maintenance, drive corrective maintenance or renewal activities.

    b. **Corrective Maintenance works.** Work undertaken in response to defects raised from the planned inspection and maintenance activities.

    c. **Value Added.** Customer services such as cable mark outs, stand over provisions for third party contractors, and provision of asset plans for the 'B4U Dig' programme, to prevent third party damage to underground assets.

4. **Asset Replacement and Renewal.** Reactive repairs and replacements that do not meet the requirements for capitalisation.

The forecast maintenance expenditure for 2016-2026 is summarised by asset class throughout this section.

6.5 Asset Maintenance and Renewal Programmes

This section describes Wellington Electricity's approach to preventative maintenance and inspections. It sets out the maintenance activities undertaken for each asset class and commentary is provided on renewal and refurbishment policies or criteria plus known systematic issues. The asset classes covered are:

- Subtransmission;
- Zone substations;
- Distribution and LV Lines;
- Distribution and LV cables;
- Distribution substations and transformers;
- Distribution switchgear;
- Other system fixed assets; and
- Other assets.

The description for each asset class is structured in the following manner:

- A summary of the fleet;
- Maintenance activities relevant to the asset class;
- The condition of the assets;
- The approach to renewals for the class including life extension activities and innovations; and
- The health indices, where these are used.

6.5.1 Subtransmission Cables

6.5.1.1 Fleet Overview

Wellington Electricity owns approximately 137 km of subtransmission cables operating at 33 kV. These comprise 50 circuits connecting Transpower GXPs to Wellington Electricity's zone substations. Approximately 31km 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 an aluminium or lead sheath. A section of the subtransmission circuits supplying Ira Street zone substation are oil-filled PIAS (paper insulated aluminium sheath) cables rated for 110kV but operating at 33kV. The lengths and age profile of this asset class are shown in Figures 6-3 and 6-4.

Construction	Design voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33kV	31%	42km
Paper Insulated, Gas Pressurised	33kV	34%	46km
Paper Insulated	33kV	7%	9km
XLPE Insulated	33kV	23%	31km
Paper Insulated, Oil Pressurised	110kV	7%	9km
Total			**137km**

Figure 6-3 Summary of Subtransmission Cables

Note: the 33kV rated cables that are run at 11kV are not included in the subtransmission circuit length.

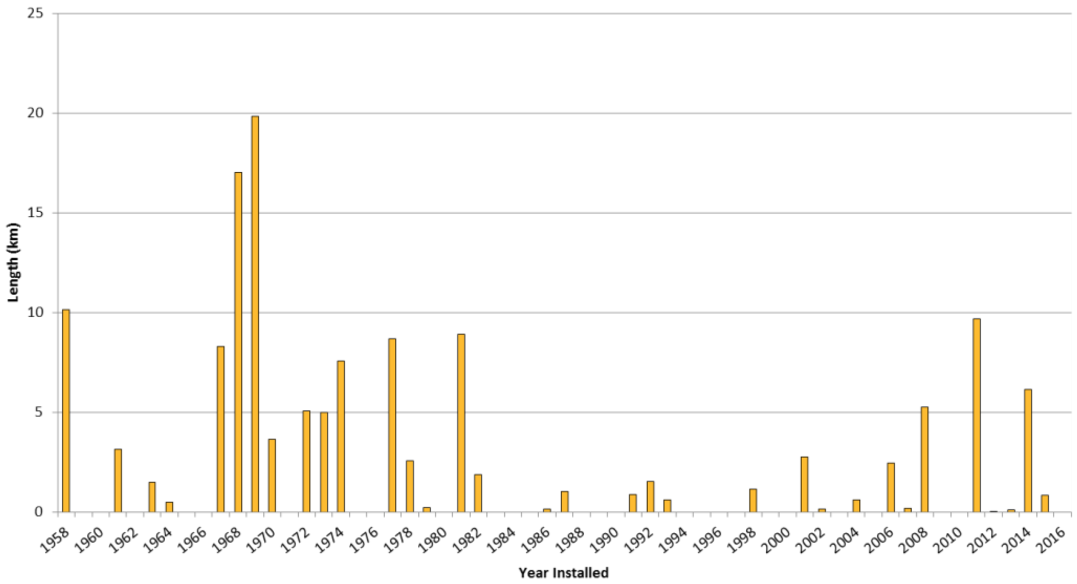


Figure 6-4 Age Profile of Subtransmission Cables

6.5.1.2 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 - regular patrol	Patrol of cable route; replace missing or damaged cable markers.	Weekly

Figure 6-5 Inspection and Routine Maintenance Schedule for Subtransmission Cables

In conjunction with the above routine maintenance schedule, all oil filled and pressurised gas cables have pressure continuously monitored via the centralised SCADA system, with managerial oversight through a monthly reporting process. This monitoring provides information that identifies cables where pressure is reducing and allows the situation to be promptly investigated. One of the key tests is the sheath test, which indicates whether there is damage to the outer sheath and gives an early indication of situations where corrosion or further damage (leading to leaks) may occur, as well as proving the integrity of the earth return path.

When fluid-filled cables develop a 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 transition joints are made to join the pressurised cables to sections of XLPE cable. These joints are relatively expensive at around $100,000 each, meaning that to replace even short sections of cable will cost a minimum of $250,000, making it uneconomic to have a large number of such joints in a single cable. The outcome of this is that where a cable is located in an environment where damage is likely to occur, it is more economical to install a long length of replacement XLPE cable than several short lengths.

Objective condition assessment on cables with oil or gas pressurisation is difficult and quite limited, as a number of assessment techniques, including partial discharge testing, are not applicable to these types of cables. The main mode of failure of these cables is stress on the joints and resulting failure, as well as sheath failures allowing gas leaks and areas of low pressurisation along the length of the cable. Accordingly, the leaks 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 to be held. Strategic spares for subtransmission cables are outlined in Figure 6-6.

Strategic Spares	
Medium lengths of cable	Medium lengths of oil and gas cable are held in store to allow replacement of short sections following damage, to allow repairs without requiring termination and transition to XLPE cable.
Standard joint fittings	Stock is held by the Field Service Provider to repair standard oil and gas joints. A minimum stock level is maintained.
Termination/transition joints	Two gas to XLPE cable transition joints are held in storage to allow the replacement of damaged sections of gas filled cables with non-pressurised XLPE cables where necessary.
Emergency overhead line corridor components	Poles, crossarms, insulators, conductors and surface foundations for two emergency overhead line corridors to be purchased during 2016.

Figure 6-6 Spares for Subtransmission Cables

6.5.1.3 Cable Condition and Failure Modes

Gas filled cables

Gas filled HV cables have been in use internationally since the 1940s and are still in service in many utilities in New Zealand and Australia. They have 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 and through structures such as bridges. Vibration from traffic has been identified as a contributing factor to some mechanical failures. This requires close monitoring of cable performance to manage any deterioration and consequent reduction in levels of service. Some of these cables in particular have been repaired numerous times as a result of third party damage or after gas leaks have been found.

Oil-Filled Cables

Oil-filled cables were installed in the Wellington Electricity network from the mid-1960s until 1991. Some circuits, for example Johnsonville in 2012 and Korokoro in 2013, have experienced significant oil leaks but in general the condition of the cables remains good for their age. The environmental impacts of leaks have been mitigated through the use of biodegradable cable fluid.

Paper and Polymeric Cables

Approximately 30% of Wellington Electricity's subtransmission cable has solid insulation of either oil-impregnated paper or XLPE. These cables are relatively new compared to the gas- and oil-filled installations.

A 33kV XLPE cable termination failed at Moore Street zone substation in 2014, causing a short outage to key customers in the Wellington CBD. This termination was subsequently found to be of a particular model that has a reputation in the New Zealand industry for premature failure and is no longer sold. The failed termination was replaced, as were the other 33kV terminations at the substation and identical terminations at The Terrace zone substation.

During 2015, faults occurred on each of the University circuits. One was the failure of a standard XLPE through joint, while the other was the failure of a gas-to-XLPE transition joint. Dissection of the failed joints, laboratory analysis of the cable insulation, and computer modelling, suggested that the cables have prematurely aged due to heating caused by high currents circulating in the cable screens. The data gathered has been used to provide a conservative estimate of the remaining life in the cable, indicating that the XLPE cable can remain in service until the gas cables become due for replacement, which is expected to be in 2024. To minimise the risk of future failures, a number of additional XLPE joints on the circuits were also proactively replaced.

With the exception of these incidents, the XLPE and paper insulated cables are performing well, and no further renewal is expected to be required during the period covered by this AMP.

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 pose a serious risk to health and safety, impact network performance, 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 the B4U-DIG programme to facilitate the provision of obstruction plans to contractors working in the area, with Northpower providing cable mark outs and stand-overs where appropriate. Wellington Electricity has a focused education campaign for contractors working for large utility companies and local authorities with presentations educating them on the importance of cable location and excavation practices.

In addition, cable maintenance staff patrol the routes of all subtransmission circuits on a weekly 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.

6.5.1.4 Renewal and Refurbishment

There are few options for refurbishment or extension of life of subtransmission cables once major leaks, discharge or electrical insulation breakdown has occurred. In most cases the most cost-effective solution is replacement of sections, or the entire length, of cable. Due to the cost of transition joints, it is likely to be more economical to replace sections end to end in their entirety.

6.5.1.5 Subtransmission Asset Health and Criticality Analysis

The Asset Health Analysis considers the attributes of each subtransmission cable circuit. For subtransmission cables the health attributes for each category are shown in Figure 6-7.

Category	Attribute
Health	Sheath Integrity
Health	Leakage History (gas- and oil-filled cables only)
Health	Known Type Issues
Health	Thermal Degradation and Loading History
Health	Partial Discharge (solid insulation only)
Health	Water Trees (XLPE insulation only)
Health	Availability of Parts
Health	Orphan Asset
Health	Repeat Failures
Health	Workforce Skills
Criticality	Primary Load Type (CBD, Industrial, Residential)
Criticality	Number of Customers Served
Criticality	Bus Configuration at Zone Substation
Criticality	Availability of 11kV back feeds

Figure 6-7 Categories and Indices for Subtransmission Circuits

Considering the above attributes for each circuit gives the health-criticality matrix shown in Figure 6-8, with individual circuit scores and ratings being presented in Figure 6-9. Where a circuit comprises multiple cable types, for example a predominantly gas-filled cable that includes a section of XLPE cable, the health indices are calculated independently for each cable type, with the lowest health index governing the AHI of the circuit as a whole.

		Lowest Impact		**Asset Criticality**			Highest Impact	
Asset Health		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				1			
	1.5				1		2	
	2.0							
	2.5			8	22			2
	3.0							
	4.0			2	8		2	
Best Health	5.0						4	

Figure 6-8 Subtransmission Circuit Health-Criticality Matrix

Subtransmission Circuit	Primary Type	AHI	ACI	Rating
University 1 & 2	Gas/XLPE	1.9	1.7	
Evans Bay 1	Gas	1.1	2.8	
Johnsonville A	Oil	1.6	2.9	
Frederick Street 1 & 2	Gas	2.8	1.3	
Moore Street 1 & 2	XLPE	4.0	1.8	
Terrace 1 & 2	XLPE	5.0	1.8	
Palm Grove 1 & 2	XLPE	5.0	1.8	
Evans Bay 2	Gas	2.5	2.8	
Johnsonville B	Oil	2.6	2.9	
Maidstone A	Gas	2.6	2.9	
Tawa A	Oil	2.7	2.9	
Hataitai 1 & 2	Gas	2.8	2.8	
Ira Street 1 & 2	Gas	2.8	2.9	
Karori 1 & 2	Gas	2.8	2.9	
Kenepuru A & B	Oil	2.8	2.9	
Korokoro A & B	Oil	2.8	2.9	
Porirua A & B	Oil	2.8	2.9	
Tawa B	Oil	2.8	2.9	
Waterloo A & B	Oil	2.8	2.9	
Maidstone B	Gas	2.7	2.9	
Waikowhai A & B	Gas	2.8	2.9	
Brown Owl A & B	Oil	2.8	3.0	
Naenae A & B	Oil	2.8	3.0	
Trentham A & B	Oil	2.7	3.0	
Waitangirua A & B	Oil	2.8	3.0	
Mana	XLPE	4.0	2.9	
Plimmerton	XLPE	4.0	2.9	
Ngauranga A & B	XLPE	4.0	2.8	
Gracefield A & B	PILC	4.0	2.9	
Seaview A & B	PILC	4.0	2.9	
Wainuiomata A & B	PILC	4.0	3.0	

Figure 6-9 Health Criticality Scores for Subtransmission Circuits

Outcome of the Asset Health Analysis

The asset health analysis shows that gas and oil-filled cables rate lower than modern cables on a number of categories, primarily driven by the cost and availability of parts and workforce skills. The highest possible health index for a gas or oil-filled cable under the AHI method is 2.8, even if it is in perfect physical condition. Accordingly, gas and oil-filled cables have the highest health based priority for replacement.

The highest priority subtransmission cable circuits, and significant changes since the 2015 Asset Management Plan, are discussed below.

University

The gas-filled University cables were largely replaced during 2008, however approximately 500 metres of gas cable remains in each circuit. These cables have high criticality due to University Zone Substation supplying a portion of the Wellington CBD, and a small shortfall in N-1 capacity that can be met with 11kV back feeds.

As discussed earlier, both circuits experienced faults on their XLPE sections during 2015, and analysis of the faults revealed issues around premature ageing of the cable insulation. Full replacement of both the gas-filled and XLPE cables is expected to be required within the next 10 years, and is provisionally planned to occur in 2024.

Evans Bay

The Evans Bay subtransmission circuits are old and in poor condition but are sufficiently lightly loaded that the Evans Bay load can be temporarily back-fed from neighbouring zone substations through the 11kV network with relative ease. Evans Bay zone substation does not appear likely to increase in criticality. There is also uncertainty around the future development of the Mt Victoria road tunnel where the cables presently run.

Analysis during 2015 has shown that the issues at Evans Bay are specifically related to Circuit 1. This circuit has a much higher rate of gas leakage than Circuit 2, resulting in a reassessment of the Circuit 2 AHI. A project will be initiated in 2016 to remove Evans Bay Circuit 1 from service in 2017, with expenditure to maintain network security as described in Section 7.

Johnsonville

Analysis during 2015 has shown that the oil-filled cables on the Johnsonville A circuit are demonstrating a small but consistent rate of fluid leakage. Work will occur during 2016 to locate and repair this leak.

Frederick Street

The gas-filled Frederick Street cables are in good condition, however their location in the Wellington CBD and capacity constraints as identified in Section 7 gives them a high criticality score. Their health will continue to be monitored through routine maintenance to watch for any deterioration in condition until they are replaced in 2018 for capacity reasons.

6.5.1.6 Expenditure Summary for Subtransmission Cables

Figure 6-10 details the expected expenditure on subtransmission cables by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
University Cable Replacement	0	0	0	0	0	0	0	875	2,625	0
Emergency Line Components (refer 5.9.14)[18]	300	300	150	0	0	0	0	0	0	0
Reactive Capital Expenditure	300	300	300	300	300	300	300	300	300	300
Capital Expenditure Total	**600**	**600**	**450**	**300**	**300**	**300**	**300**	**1,175**	**2,925**	**300**
Preventative Maintenance	116	116	116	116	116	116	116	116	114	114
Asset Renewal and Replacement Opex	307	323	308	323	345	366	390	413	432	443
Operational Expenditure Total	**423**	**439**	**424**	**439**	**461**	**482**	**506**	**529**	**546**	**557**

Figure 6-10 Expenditure on Subtransmission Cables ($K in constant prices)

6.5.2 Zone Substations

6.5.2.1 Zone Substation Transformers and Tap Changers

Fleet Overview

Wellington Electricity has 52 33/11kV power transformers in service on the network, and two spare units. The age profile for zone substation transformers is shown in Figure 6-11.

[18] A nominal amount of expenditure is included for emergency corridors but the full amount will be identified in the 2016 resiliency study.

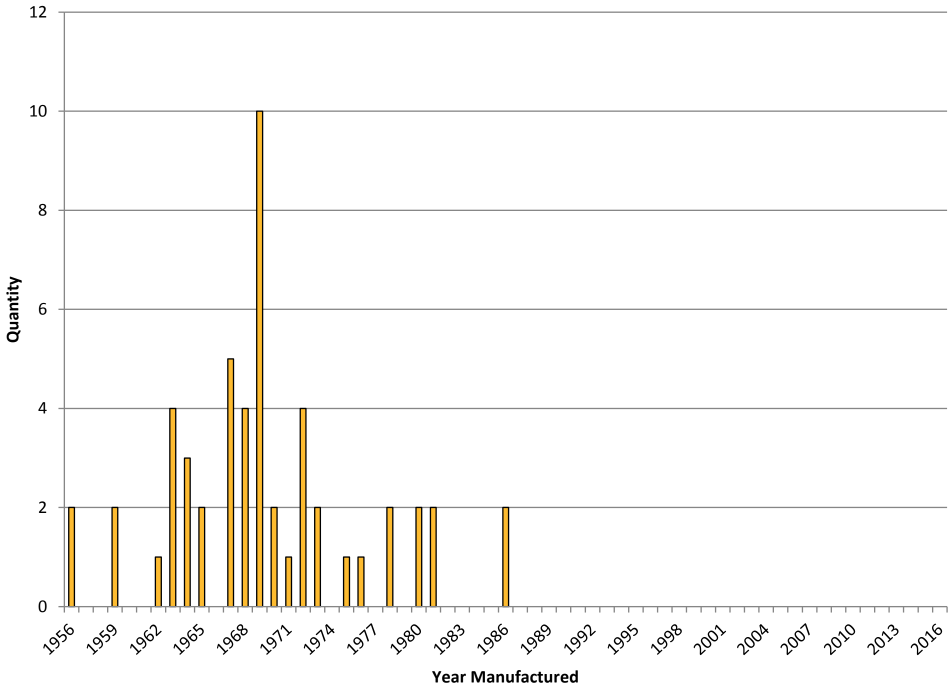


Figure 6-11 Age Profile of Zone Substation Transformers

The mean age of the transformer fleet is 46 years.

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on zone substation power transformers:

Activity	Description	Frequency
Transformer oil test	Dissolved gas analysis (DGA) testing of transformer main tank oil.	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
OLTC maintenance	Programmed maintenance of OLTC.	4 yearly

Figure 6-12 Inspection and Routine Maintenance Schedule for Zone Substation Transformers

Strategic Spares

Wellington Electricity holds critical spares for the power transformers and tap changers as detailed in Figure 6-13.

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 operation. Where excessive wear is noted during maintenance, spares are ordered and held in stock for that model of tap changer. Spares are still available for most models on the network, and if necessary 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. Fittings include Buchholz relays, high voltage bushings etc. If major repairs are needed, a unit will be swapped out.
Spare transformers	Two spare power transformers are available. One unit came from Petone substation when this was decommissioned in 2013 and is held at the Bouverie Street yard. Another is the newly refurbished Wainuiomata A, which is held at the Wainuiomata zone substation. Should additional spare transformers be required, one could be taken from any of a number of substations that are lightly loaded with sufficient distribution network back-feed options. These include Gracefield, Tawa and Kenepuru.

Figure 6-13 Spares Held for Zone Substation Transformers

Transformer Condition

All zone substation transformers are operated well within their ratings, are regularly tested, and have had condition assessments undertaken. Where evidence of heating is present, corrective maintenance such as tightening or renewing internal connections outside of the core or tap changer maintenance is undertaken, if economic. The most common issue is mechanical deterioration. Examples include tap changer mechanism wear, contact wear, and similar problems associated with moving machinery. External condition issues include leaking gaskets, fan and cooling system problems and, for outdoor installations, corrosion and weathering of the transformer tanks, especially the tops where water can sometimes pool.

Oil analysis can provide an estimated Degree of Polymerisation (DP) value for the paper insulation which provides an initial overview of the transformer condition. Furan analysis undertaken with the DGA oil tests in 2009 show the DP of the majority of transformers to be above 450 indicating at least 25 years of remaining life in the insulation. Once a transformer DP reaches 300, a paper sample will be taken to confirm the accuracy of the furan analysis.

During 2013, routine oil testing of Wainuiomata A indicated abnormal internal heating. The unit was replaced with a spare, and sent to a workshop for further evaluation. The fault was found to be a stray earth contact inside the tank. A sample of the insulating paper gave a DP result of 958, indicating that the insulation has a remaining life of 45 years despite already being 42 years old. On this basis the fault was repaired and the transformer refurbished to be held as a spare.

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 inform the assessment of whether a major transformer refurbishment would be economic.

The following projects have been provided for in the asset maintenance and replacement forecasts for the planning period:

- Ongoing preventative maintenance including testing and inspections;
- Transformer replacements at two zone substations; and
- Ongoing transformer refurbishment costs.

Based on asset health and criticality, two zone substation transformers can be expected to require replacement during the period 2016 to 2026. The units to be replaced may not be the oldest nor in the worst condition, but will be transformers where capacity and security constraints indicate a high risk associated with failure. All factors considered in the replacement decision-making process are covered in the Asset Health Analysis described below.

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. For the power transformers in the Wellington Electricity network, the testing and inspection programme will aid in getting the best life from the transformer and optimal timing of replacement of the unit.

Transformer Asset Health and Criticality Analysis

The Asset Health Analysis considers the attributes of each power transformer as defined by the properties shown in Figure 6-14.

Category	Index
Health	Degree of Polymerisation
Health	Bushing Condition
Health	Mechanical Integrity (i.e. SFRA testing)[19]
Health	Insulation System Condition
Health	Known Type or Design Issues
Health	Safety Features
Health	Availability of Parts for OLTC Maintenance
Health	Noise
Health	Workforce Skills
Criticality	Primary Load Type (CBD, Industrial, Residential)
Criticality	Number of Customers Served
Criticality	Bus Configuration at Zone Substation
Criticality	Availability of 11kV Back feeds
Criticality	Installation Issues, e.g. access restrictions

Figure 6-14 Categories and Indices for Power Transformers

[19] Transformer SFRA testing is not currently undertaken by Wellington Electricity.

Applying the above factors to each transformer gives the health-criticality matrix shown in Figure 6-15, with individual transformer scores and ratings being presented in Figure 6-16.

	Asset Criticality: Lowest Impact						Highest Impact
Asset Health	5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health 1.0				1			
1.5				1			
2.0				1			
2.5			2	10		2	
3.0			4	15		2	1
4.0			2	6		2	3
Best Health 5.0							

Figure 6-15 Power Transformer Health-Criticality Matrix

Transformer	Substation	AHI	ACI	Rating
Evans Bay T1	Evans Bay	1.3	2.8	
Evans Bay T2	Evans Bay	1.7	2.8	
Palm Grove T1 & T2	Palm Grove	2.9	1.7	
Frederick Street T1	Frederick Street	3.0	1.4	
Frederick Street T2	Frederick Street	4.0	1.4	
Mana	Mana-Plimmerton	2.0	2.9	
Moore Street T1	Moore Street	4.0	1.8	
Moore Street T2	Moore Street	3.0	1.8	
Terrace T1 & T2	Terrace	4.0	1.3	
University T1	University	3.0	1.7	
University T2	University	4.0	1.7	
Brown Owl A	Brown Owl	3.0	3.0	
Brown Owl B	Brown Owl	2.9	3.0	
Gracefield A & B	Gracefield	3.0	2.9	
Hataitai T1 & T2	Hataitai	3.0	2.8	
Ira Street T1 & T2	Ira Street	4.0	2.9	
Johnsonville A & B	Johnsonville	2.9	2.9	
Karori T1	Karori	2.9	2.9	
Karori T2	Karori	3.0	2.9	
Kenepuru A	Kenepuru	4.0	2.9	
Kenepuru B	Kenepuru	3.0	2.9	
Korokoro A & B	Korokoro	3.0	2.9	
Maidstone A	Maidstone	4.0	2.9	
Maidstone B	Maidstone	3.0	2.9	

Transformer	Substation	AHI	ACI	Rating
Naenae T1 & T2	Naenae	3.0	3.0	
Ngauranga A	Ngauranga	2.9	2.8	
Ngauranga B	Ngauranga	3.0	2.8	
Plimmerton	Mana-Plimmerton	2.9	2.9	
Porirua A & B	Porirua	3.0	2.9	
Seaview A & B	Seaview	3.0	2.9	
Tawa A	Tawa	2.8	2.9	
Tawa B	Tawa	2.7	2.9	
Trentham A & B	Trentham	2.8	3.0	
Waikowhai T1	Waikowhai	2.8	2.9	
Waikowhai T2	Waikowhai	2.7	2.9	
Wainuiomata A	Wainuiomata	3.0	3.0	
Wainuiomata B	Wainuiomata	4.0	3.0	
Waitangirua A	Waitangirua	4.0	3.0	
Waitangirua B	Waitangirua	3.0	3.0	
Waterloo A & B	Waterloo	4.0	2.9	

Figure 6-16 Health-Criticality Scores for Power Transformers

Outcome of Asset Health and Criticality Analysis

Figure 6-17 shows the health of the power transformer fleet by unit age, against the theoretical trend in health over time. This shows that a large number of units are in better health than would be expected for their age. This is due to a number of factors, particularly the proportion of units located indoors and therefore less vulnerable to corrosion, and loading on transformers being kept below 50% for security reasons. Exceptions to this are noted below.

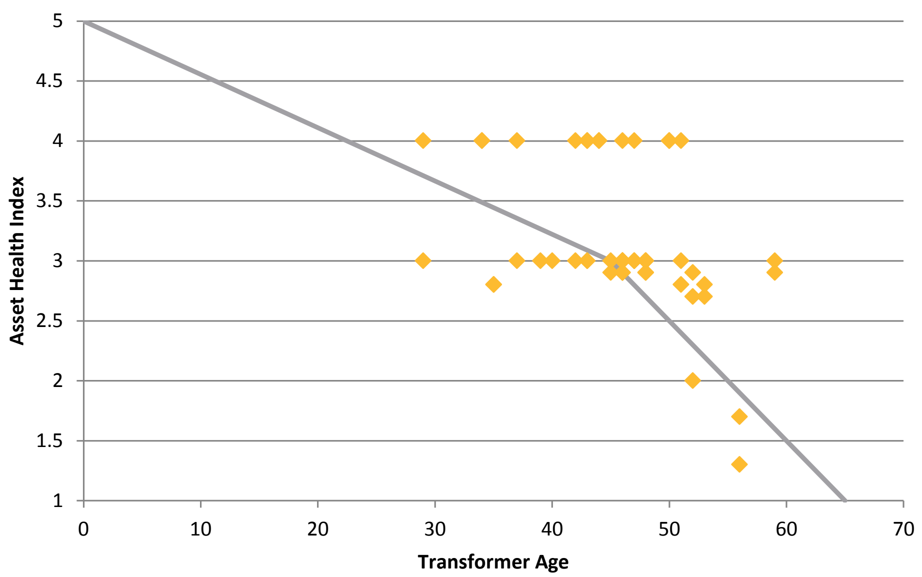


Figure 6-17 Asset Health vs Age for Power Transformers

Evans Bay

The transformers at Evans Bay were installed in 1959 and have the lowest health indices in the network. These transformers have experienced an increasing number of problems in recent years, mostly relating to the mechanical performance of the tap changer and excessive leaks due to deterioration of valves, flanges, gaskets and radiators. Fortunately to date 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. However 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 anticipated that these transformers will be replaced with refurbished ex-Palm Grove transformers, once those units are replaced in 2019.

Palm Grove

The Palm Grove transformers are in good condition, but have high criticality due to the peak loading and number of customers supplied by the substation. Their asset health is marked down slightly due to the noise created by their forced cooling and the proximity of residential neighbours. The proposed development path outlined in Section 7 requires the replacement of these transformers with higher-rated units in 2019. The need for the new transformers to meet noise restrictions will form part of the specification of this project.

Ngauranga

Ngauranga has two of the oldest power transformers installed in Wellington Electricity's network. These transformers are generally reliable but have experienced problems with the tap changer diverter switches in the past. These issues will be monitored and corrective repairs undertaken as required. It is expected that replacement due to condition will be required at the end of the planning period, however as identified in Chapter 7, replacement of the transformers is planned for 2019 due to capacity constraints.

Frederick Street

Frederick Street has a high criticality index due to its location in Wellington CBD and the number of customers it supplies. The transformers are in good condition, however in early 2014 the DGA results on T1 and T2 indicated elevated levels of ethylene and moisture respectively. In both cases, the absence of other key gases suggested there were no major problems with either unit so the oil was filtered and routine monitoring will continue.

Waikowhai Street

The transformers at Waikowhai Street substation are in good condition. They are fitted with vertical Reinhausen tap changers which are the only two of this kind on the network. These are more difficult to maintain and are refurbished on a 6-8 yearly cycle. The tap changers were last refurbished in 2011 by a Reinhausen technician and it is expected that further work will not be required until 2019.

University 1

The University transformers are only 28 years old, however University 1 is showing a much lower degree of polymerisation than University 2. This is attributed to a historic loading imbalance which has since been resolved. While the DP result is low it is still indicating an estimated remaining life of 25 years so replacement is not expected to be required within the planning period. The condition of both units will continue to be monitored through the routine maintenance programme.

6.5.2.2 Expenditure Summary for Power Transformers

Figure 6-18 details the expected expenditure on power transformers by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Evans Bay Transformer Replacement	0	0	0	250	750	0	0	0	0	0
Capital Expenditure Total	**0**	**0**	**0**	**250**	**750**	**0**	**0**	**0**	**0**	**0**
Preventative Maintenance	125	125	125	105	95	105	100	105	95	105
Corrective Maintenance	21	22	22	24	25	27	29	31	32	35
Operational Expenditure Total	**146**	**147**	**147**	**129**	**120**	**132**	**129**	**136**	**127**	**140**

Figure 6-18 Expenditure on Power Transformers
($K in constant prices)

6.5.2.3 Zone Substation Switchboards and Circuit Breakers

Fleet Overview

11kV circuit breakers are used in zone substations to control the power injected in to the 11kV distribution network. The most common single type is Reyrolle Pacific type LMT circuit breakers. There are 329 circuit breakers located at zone substations on the Wellington Electricity network. An age profile of these circuit breakers is shown in Figure 6-19.

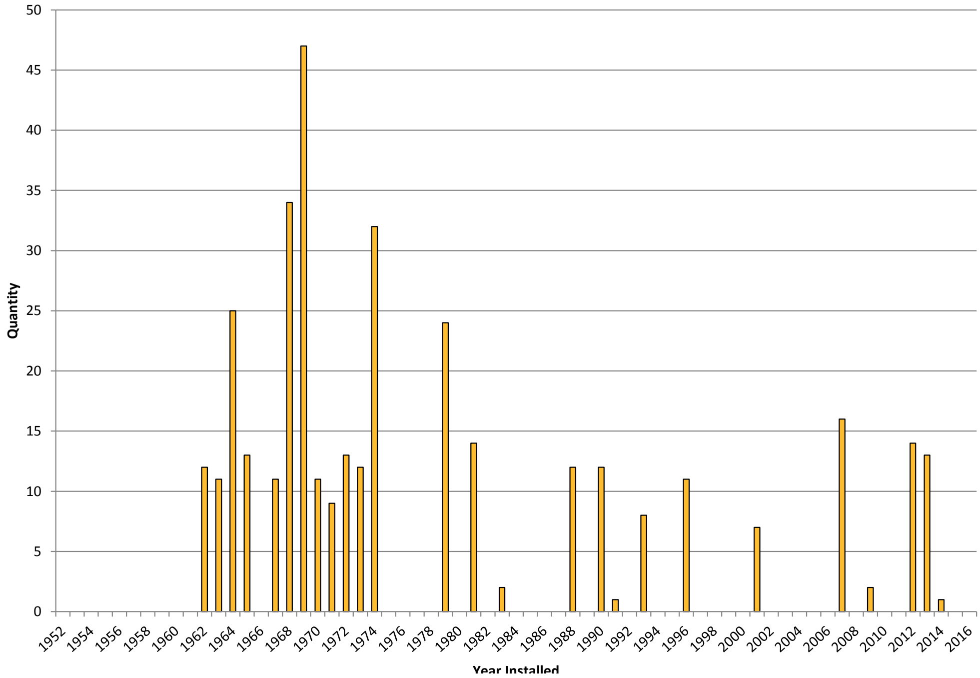


Figure 6-19 Age Profile for Zone Substation Circuit Breakers

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. Older circuit breakers are oil filled while newer units have vacuum interrupters. The majority of circuit breakers are still oil filled and require relatively intensive maintenance regimes.

The use of transformer feeders avoids the need for 33kV circuit breakers at zone substations. However, there are two 33kV Nissin KOR oil circuit breakers at Ngauranga which have been in service at this site for approximately 23 years. Originally manufactured in the 1960s, installation was in 1993 when the substation was constructed.

Category	Quantity
33kV Circuit Breakers	2
11kV Circuit Breakers	367

Figure 6-20 Summary of Zone Substation Circuit Breakers

Manufacturer	Breaker Type	Quantity
Nissin (33kV)	Oil	2
Reyrolle	Oil	283
	Vacuum	68
Siemens	SF_6	16
Total		**369**

Figure 6-21 Summary of Zone Substation Circuit Breakers by Manufacturer

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on metal clad switchboards and circuit breakers at zone substations:

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
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
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
11kV Switchboard Major Maintenance	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
11kV Circuit Breaker - Annual Operational Check	Back-feed supply, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication.	Annually
PD Location by External Specialist	External specialist to undertake partial discharge location service.	Annually

Figure 6-22 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

In addition to the routine maintenance programme, oil circuit breakers are maintained as required following a number of fault clearance operations.

Strategic Spares

Given the high number of circuit breakers in service on the Wellington Electricity network, it is important to keep adequate quantities of spares to enable fast repair of minor defects. The largest quantity of circuit breakers on the network is the Reyrolle type LMT, which is used predominantly at zone substations, and Wellington Electricity holds large numbers of spares for these circuit breakers. Furthermore, the RPS (formerly Reyrolle Pacific) switchgear factory is located in Petone which means that spares are available within short timeframes if required for LMT type switchgear. An overview of strategic spares held for circuit breakers is shown in Figure 6-23.

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.
Current transformers and primary bars	Where available, spare current transformers and primary bars are held to replace defective units. In particular, 400A current transformers for Reyrolle LMT are held, as this type of equipment has a known issue with partial discharge.

Figure 6-23 Spare Parts Held for Circuit Breakers

Switchgear Condition

The switchgear installed on the Wellington Electricity network is generally in very good condition although there is some deterioration of older units. The equipment is installed indoors, has not been exposed to extreme operating conditions and has been well maintained. In some locations, the type of load served, or the known risks with the type of switchgear, means that an enhanced maintenance programme is required whilst a replacement programme is in place for some older switchgear types, for example Reyrolle Type C.

Examples of poor condition include: partial discharge (particularly around cast resin components), corrosion and compound leaks that are visible externally, slow or worn mechanisms and unacceptable contact wear. The majority of these defects can be easily remedied under corrective maintenance programmes.

The condition of zone substation switchboards is discussed in detail in the circuit breaker health-criticality analysis below. Due to their lower criticality, distribution substation switchboards are not currently included in the analysis.

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 are put in place to manage risks until replacement is possible. A large number of older circuit breakers are still in service and are in excellent condition due to regular maintenance over their service life. However other 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 when a circuit breaker is replaced. Other drivers that influence the replacement decision include safety, criticality, operability and co-ordination with modern equipment.

The following replacement programmes are in place for the planning period:

Reyrolle Type C

Reyrolle Type C circuit breakers were installed between 1938 and the late 1960s and the majority of units have reached the end of their effective service life. There are 13 units remaining in service at Gracefield zone substation and these are to be replaced over the next two years.

Reyrolle LMT - Partial Discharge

Reyrolle LMT circuit breakers were installed on the network from late 1960s onwards. There are over 600 units in service on the Wellington Electricity network.

In the latter part of 2012, a Reyrolle LMT circuit breaker at Waitangirua zone substation was found to have high levels of partial discharge emanating from the CT chamber. This prompted a replacement of the CTs, bushings and pitch-filled cable termination using a specially developed retrofit kit, which lowered the PD to normal levels. Circuit breakers are refurbished using this kit when they are identified as having unacceptable partial discharge levels.

All circuit breakers are surveyed with a handheld partial discharge meter as part of their routine annual general inspection, with zone substation circuit breakers receiving a full partial discharge survey annually from an external specialist. Corrective maintenance is undertaken when high levels of PD are detected. At this stage there do not appear to be any other type issues with LMT.

Reyrolle LMT – Rotary Auxiliary Switch Failure

During 2011 a number of instances of circuit breaker “failure to operate” alarms 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 a high level of a styrene residue was found, as well as other oil and grime. Although the cause is uncertain, it is suspected that previous maintenance practices have introduced solvents that have released the glues and plastics inside the switch body. These have migrated onto the contacts and act as an insulator leading to the “failure to operate” issues.

The Field Services Provider has been trained in the correct maintenance practices, including the appropriate corrective actions when a faulty unit is found. In addition, dust covers are fitted to cleaned contacts to prevent dust and grime ingress. The switchgear manufacturer is now providing factory made dust covers on new circuit breakers of this type supplied to Wellington Electricity.

After the introduction of dust covers and the corrective maintenance regime to clean the contacts, reports of “failure to operate” alarms on LMT type circuit breakers has been reduced. This outcome is expected to improve further when all the LMT circuit breakers are maintained and installed with dust covers on the auxiliary switches.

Circuit Breaker Asset Health and Criticality Analysis

The Asset Health-Criticality analysis considers the attributes of each zone substation switchboard as defined by the properties shown in Figure 6-24.

Category	Attribute
Health	External Condition
Health	Interrupter Life and Operation Count
Health	Insulation Properties
Health	Partial Discharge
Health	Gas/Oil Leaks
Health	Type or Design Issues
Health	Operating History
Health	Availability of Parts and Tools
Health	Orphan Asset
Health	Uncertified Modifications
Health	Workforce Skills
Health	Failure Containment and Operator Safety
Criticality	Primary Load Type (CBD, Industrial, Residential)
Criticality	Number of Customers Served
Criticality	Bus Configuration at Zone Substation
Criticality	Availability of 11kV Back feeds

Figure 6-24 Categories and Indices for Zone Substation Switchboards

Considering the above attributes for each switchboard gives the health-criticality matrix shown in Figure 6-25, with individual switchboard scores and ratings being presented in Figure 6-26.

		Lowest Impact		**Asset Criticality**			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				1			
	1.5			1	2		1	1
Asset Health	2.0						1	
	2.5			5	13		2	
	3.0							
	4.0				1			
Best Health	5.0				2		2	

Figure 6-25 Zone Substation Switchboard Health-Criticality Matrix

11kV Switchboard	Model	AHI	ACI	Rating
Frederick Street	LM23T	1.9	1.3	
University	LMT	1.9	1.7	
Kaiwharawhara	LMVP	2.0	1.8	
Gracefield	C	1.2	2.9	
Mana	LM23T	1.8	2.8	
Johnsonville	LM23T	1.8	2.9	
Brown Owl	LM23T	1.8	3.0	
Moore Street	LM23T	2.8	1.8	
Nairn Street	LMT	2.9	1.8	
Palm Grove	LMVP	5.0	1.8	
Terrace	NX-PLUS	5.0	1.8	
Evans Bay	LMVP	5.0	2.8	
Hataitai	LM23T	2.8	2.8	
Ira Street	LM23T	2.8	2.9	
Karori	LMVP	5.0	2.9	
Kenepuru	LM23T	2.8	2.9	
Korokoro	LM23T	2.8	2.9	
Maidstone	LM23T	2.8	2.9	
Naenae	LM23T	2.9	3.0	
Ngauranga	LMT	2.9	2.8	
Petone	LM23T	2.9	2.9	
Plimmerton	LM23T	2.8	2.9	
Porirua	LM23T	2.9	2.9	
Seaview	LM23T	2.9	2.9	
Tawa	LM23T	2.9	2.9	
Titahi Bay	LMT	2.9	3.0	
Trentham	LM23T	2.9	3.0	
Waikowhai	LMT	4.0	2.9	
Wainuiomata	LMT	2.9	3.0	
Waitangirua	LM23T	2.9	3.0	
Waterloo	LMT	2.9	2.9	

Figure 6-26 Health-Criticality Scores for Zone Substation Switchboards

Outcome of the Asset Health Analysis

Frederick Street

The Reyrolle LMT switchboard at Frederick Street had partial discharge mitigation work during 2015. Initial TEV testing indicates that this work has been successful with full PD retesting in 2016 expected to confirm this and allow a re-evaluation of its health score. Apart from the partial discharge issue, the switchboards are in good health but have high criticality due to their location in the Wellington CBD.

University

The Reyrolle LMT switchboard at University has two circuit breakers that are planned for partial discharge mitigation work in 2016.

Kaiwharawhara

The Reyrolle LMVP switchboard at Kaiwharawhara has given unusual readings during partial discharge testing but the cause has not been able to be identified. Detailed investigation and mitigation is planned to occur during 2016.

Gracefield

The Gracefield switchboard is Reyrolle Type C which has multiple design issues and is being phased out of the network, as discussed earlier. The replacement of the Gracefield switchboard is planned for commencement in 2017.

Partial Discharge Mitigation

Three other Reyrolle LMT switchboards have circuit breakers planned for partial discharge mitigation during 2016, being:

- Brown Owl;
- Johnsonville; and
- Mana.

Other Comments

Wellington Electricity's fleet of zone substation circuit breakers is generally in good condition. Apart from the replacement of the remaining Reyrolle Type C switchboard, and assuming that the partial discharge mitigation refurbishments continue to be successful, no zone substation circuit breakers are expected to require replacement for health reasons during the next five years. During the period 2021-2025, three zone substation switchboards will exceed 60 years of age. There is no indication that replacement of these switchboards needs to be driven purely by age, however their condition will continue to be monitored through routine maintenance.

Further improvements in circuit breaker health are planned to be achieved through installing arc fault containment measures, particularly at Wellington CBD zone substations where system fault levels are high relative to switchgear ratings, and general refurbishment including replacement of oil circuit breaker trucks with vacuum technology.

6.5.2.4 Expenditure Summary for Zone Substation Circuit Breakers

Figure 6-27 details the expected expenditure on zone substation circuit breakers by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Partial Discharge Mitigation	225	0	0	0	0	0	0	0	0	0
Gracefield Switchboard Replacement	275	1,100	825	0	0	0	0	0	0	0
Moore Street Switchboard Refurbishment	180	540	0	0	0	0	0	0	0	0
Nairn Street Switchboard Refurbishment	0	180	540	0	0	0	0	0	0	0
Frederick Street Switchboard Refurbishment	0	0	200	600	0	0	0	0	0	0
University Switchboard Refurbishment	0	0	0	160	480	0	0	0	0	0
Reactive Capital Expenditure	50	50	50	50	50	50	50	50	50	50
Capital Expenditure Total	**730**	**1,870**	**1,615**	**810**	**530**	**50**	**50**	**50**	**50**	**50**
Preventative Maintenance	149	147	138	137	136	136	136	136	136	136
Corrective Maintenance	23	21	21	21	21	21	21	22	22	22
Operational Expenditure Total	**172**	**168**	**159**	**158**	**157**	**157**	**157**	**158**	**158**	**158**

Figure 6-27 Expenditure on Zone Substation Switchboards ($K in constant prices)

6.5.2.5 Zone Substation Buildings and Equipment

Fleet Overview

There are 27 zone substation buildings, and three major 11kV switching station buildings. The buildings are typically standalone, although some in the CBD are close to adjacent buildings or, in the case of The Terrace, located inside a larger customer-owned building.

The age profile of the major substation buildings is shown in Figure 6-28. The average age of the buildings is 44 years. There are five locations where Wellington Electricity does not own the land under the zone substation and has a long-term lease with the landowner.

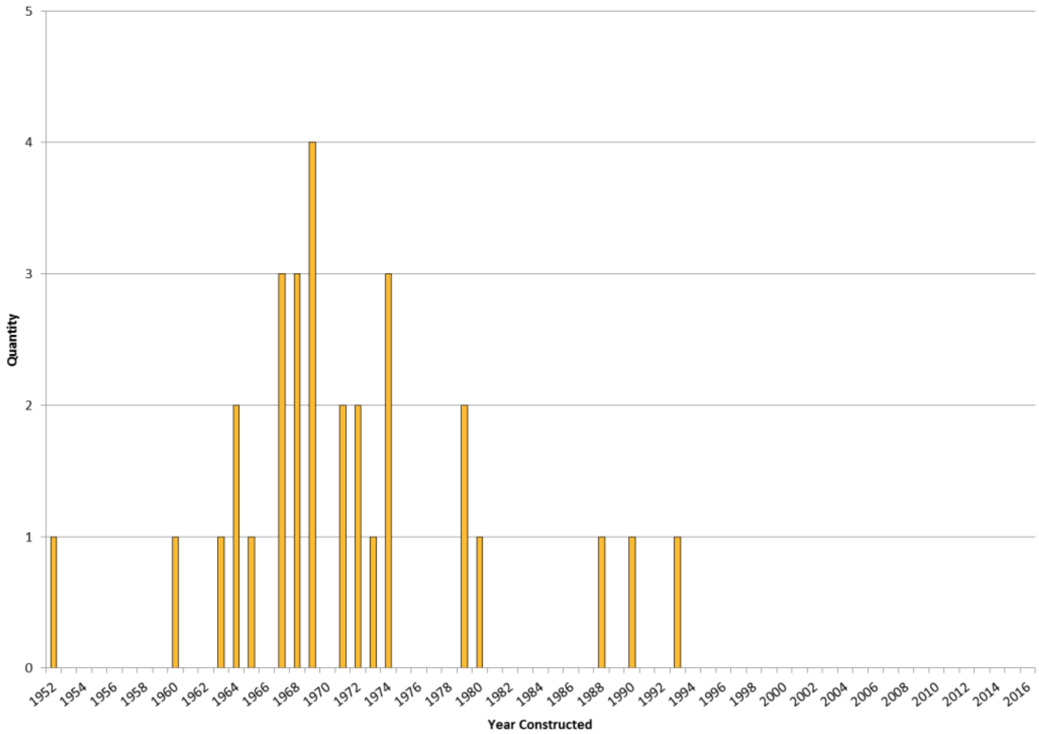


Figure 6-28 Age Profile of Major Substation Buildings

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on zone 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 6-29 Inspection and Routine Maintenance Schedule for Zone Substations and Equipment

Routine zone substation inspections are undertaken quarterly and 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.

Renewal and Refurbishment

The substation building refurbishment programme 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 weather tightness issues and these components are replaced in their 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.

Wellington Electricity completes seismic investigations prior to undertaking any major substation work and this may lead to additional seismic strengthening works. The seismic reinforcing of substation buildings and how this risk is managed is discussed in Sections 5.9.12 and 6.6.

6.5.2.6 Expenditure Summary for Zone Substation Buildings

Figure 6-30 details the expected expenditure on zone substation buildings by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Seismic Strengthening[20]	230	140	375	0	0	0	0	0	0	0
Reactive Capital Expenditure	200	200	200	200	200	200	200	200	200	200
Capital Expenditure Total	**430**	**340**	**575**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Preventative Maintenance	30	30	30	30	30	30	30	30	30	30
Corrective Maintenance	120	120	120	120	120	120	120	120	120	120
Operational Expenditure Total	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**

Figure 6-30 Expenditure on Zone Substation Buildings ($K in constant prices)

[20] Refer to Figure 6-49 for details of expenditure on seismic strengthening of distribution substations.

6.5.3 Overhead Lines

6.5.3.1 Poles

The total number of poles owned by Wellington Electricity, including subtransmission distribution lines and low voltage lines, is 36,694. Of this number, 26% are wooden poles and 74% are concrete poles. Another 16,404 poles are owned by other parties but have Wellington Electricity assets such as crossarms and conductors attached, for example telecommunication poles owned by Chorus, or the poles for the trolley bus network (owned by Wellington Cable Car Limited). A summary of the poles either owned by Wellington Electricity, or with Wellington Electricity assets attached, is shown in Figure 6-31.

Pole Owner	Wood	Concrete	Total
Wellington Electricity	9,436	27,258	36,694
Customer	10,961	2,308	13,269
Chorus	1,027	56	1,083
Wellington Cable Car Limited	1,308	744	2,052
Total	**22,732**	**30,366**	**53,098**

Figure 6-31 Summary of 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 and nearly 40% of all wooden poles are older than 45 years (the standard asset life of wooden poles). Crossarms are predominantly hardwood. An age profile of poles owned by Wellington Electricity is shown in Figure 6-32.

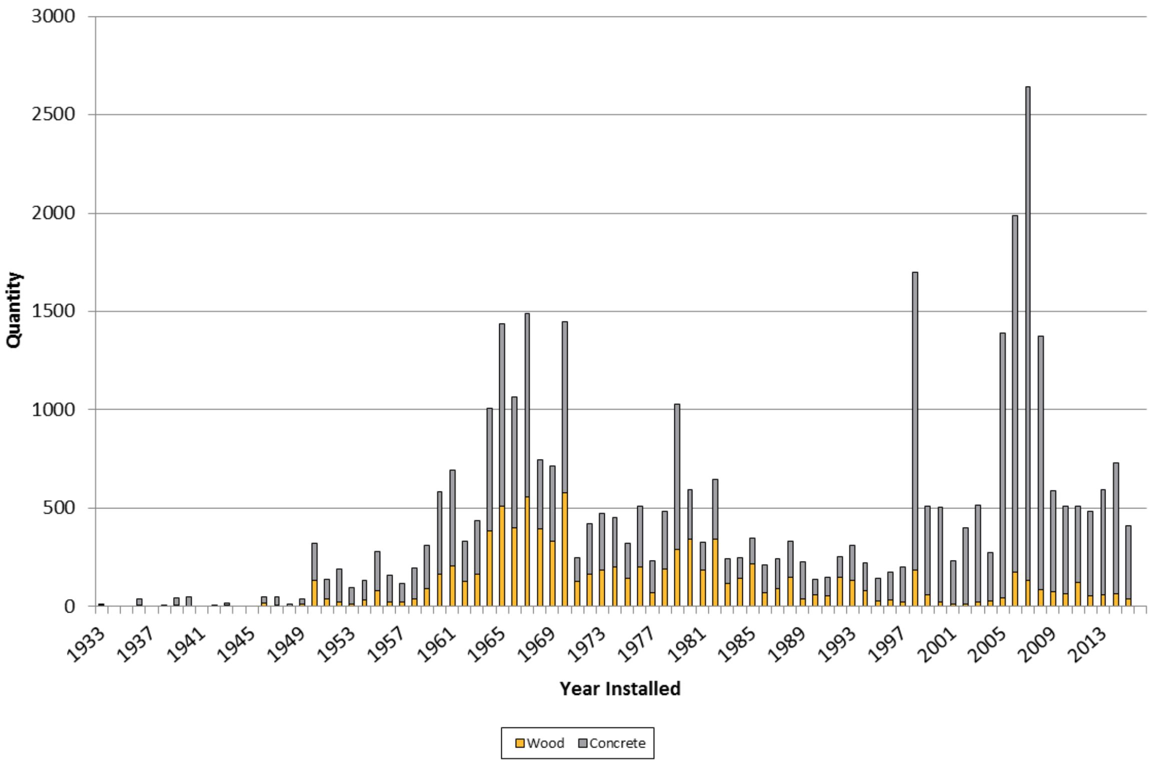


Figure 6-32 Age Profile of Poles

As Wellington Electricity does not own customer service lines or poles, there is on-going work required to advise consumers of their responsibilities relating to these privately owned lines. Owners are notified of any identified defects or when hazards are identified on consumer owned poles or service lines.

Wellington Electricity has an interest in customer poles that are considered as works as generally defined in the Electricity Act 1992. An example is for a pole supplying multiple customers along a private right of way. Where appropriate, Wellington Electricity may undertake replacement of privately owned works at its own cost and those works will then become Wellington Electricity owned assets.

In addition to electricity distribution services, Chorus, Vodafone and CityLink utilise Wellington Electricity's poles for telephone, cable TV and UFB services.

6.5.3.2 Subtransmission Lines

Wellington Electricity's 58km of 33kV subtransmission overhead lines are predominantly AAC conductor on both wood and concrete poles. Overhead line was used for subtransmission in the Hutt Valley and Porirua areas, converting to underground cable at the urban boundary. Subtransmission overhead lines are typically located on rural or sparsely developed land, although they are also in some other locations where difficult access would have made underground cable installation problematic. A summary and age profile of the subtransmission lines are shown in Figure 6-33 and Figure 6-34.

Category	Quantity
33kV Overhead Line	58km

Figure 6-33 Summary of Subtransmission Lines

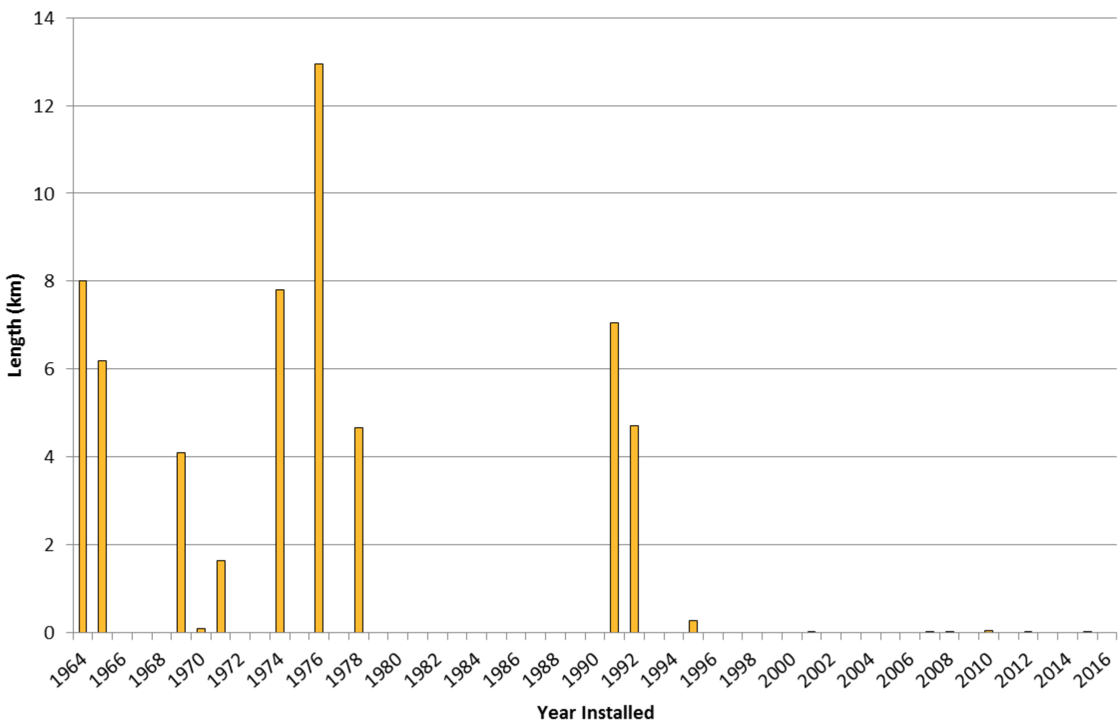


Figure 6-34 Age Profile of Subtransmission Line Conductors

6.5.3.3 Distribution and Low Voltage Conductors

Overhead conductors are predominantly aluminium conductor (AAC), with older lines being copper. In some areas aluminium conductor steel reinforced (ACSR) conductors have been used, with these having aluminised steel cores due to the high salt presence in the Wellington Electricity network area. New line reconstruction utilises all aluminium alloy conductor (AAAC). Most low voltage conductors are PVC covered, and low voltage aerial bundled conductor (LV ABC) has been used in a small number of tree encroachment areas, subject to District Plan allowances. Figure 6-36 shows the age profile of overhead line conductors.

Category	Quantity
11kV Line	594km
Low Voltage Line	1,091km
Streetlight Conductor	809km

Figure 6-35 Summary of Distribution Overhead Lines

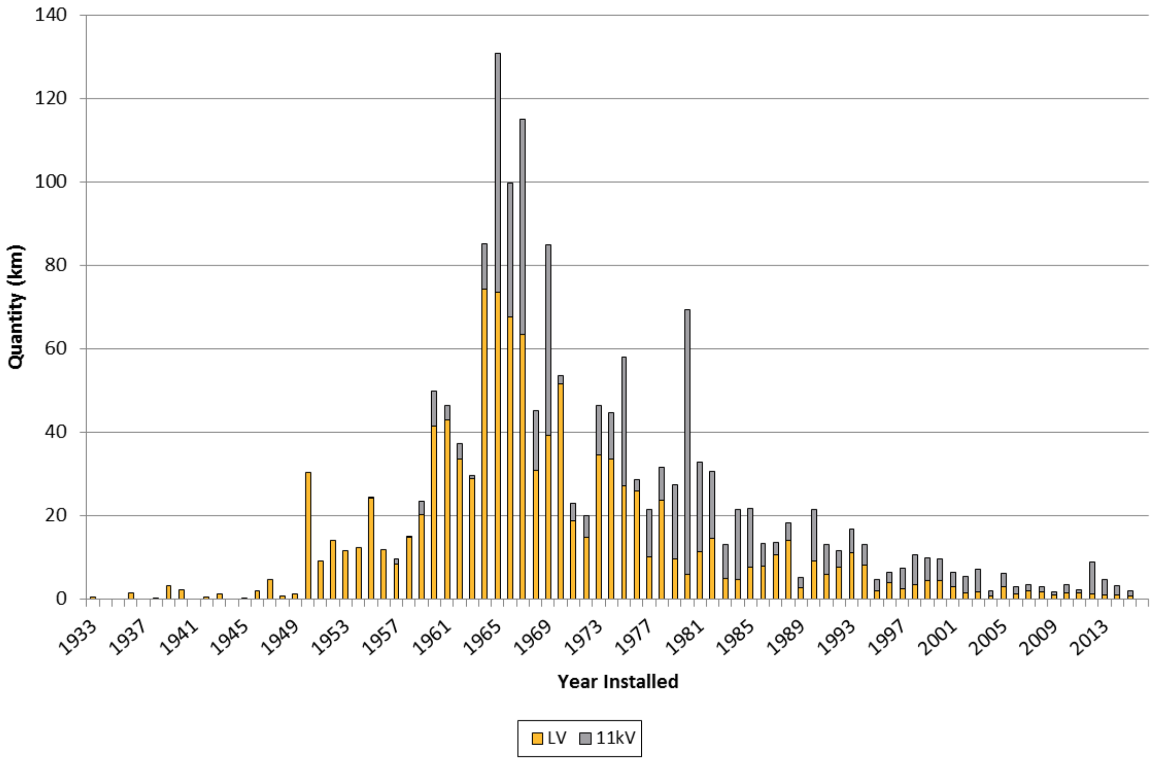


Figure 6-36 Age Profile of Distribution Overhead Line Conductors

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. 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 on-board battery, replacement onto live line using hot stick.	8 yearly

Figure 6-37 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 or safety issues. In addition, all connectors in the current carrying path get a thermal scan to identify any high resistance joints which could potentially fail due to heating. These inspections drive a large part of the overhead corrective maintenance works and also contribute to asset replacement programmes for insulators and crossarms.

Wellington Electricity has been using the Deuar MPT40 to test its wooden pole population since 2011. The testing programme ensures the detection of structural issues along the length of the pole, including below ground level, and also provides useful remaining life indicators. Approximately 2,000 poles are Deuar tested every year.

Pole Condition

The majority of poles on the Wellington Electricity network are in good condition as the 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 area are concrete, which are durable and in good condition. The remainder are timber poles, which are tested and replaced in accordance with their Deuar serviceability index results or where there are visible structural defects.

Common condition issues with timber poles are deterioration of pole strength due to internal or external decay. Poles are also leaning, have head splits or incur 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 Vodafone and Chorus on network poles.

Wellington Electricity has a standard that governs third party attachments to network poles. This standard will ensure future connections to poles for telecommunications infrastructure meet Wellington Electricity's requirements and do not have an injurious effect on the network or the safety of contractors and members of the public. Third party network operators are required to contribute to the upgrade of network poles where there will be an adverse impact on pole service life or safe working load as the result of additional infrastructure connections.

Figure 6-38 shows the health-criticality matrix of Wellington Electricity's fleet of poles. Pole asset health is determined solely by the unit's condition ranking, while asset criticality is determined by the voltage of the lines connected to the pole and the number of customers that they supply.

		Lowest Impact		**Asset Criticality**			Highest Impact	
Asset Health		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0	42	16	24	6	2	1	
	1.5							
	2.0	880	302	281	101		1	
	2.5							
	3.0	10,391	2,414	2,925	781	21	62	
	4.0	5,317	722	1,010	496	7	11	
Best Health	5.0	6,723	1,402	2,081	661	1	13	

Figure 6-38 Pole Health-Criticality Matrix

Overhead Line Condition

Pin type insulators are no longer used for new 33kV or 11kV line construction as they develop reliability issues later in life such as split insulators due to pin corrosion, or leaning on crossarms due to the bending moment on the pin causing the cross arm hole to wear. There is no programme to proactively replace existing pin type insulators but replacement occurs when defects are identified or when crossarms require replacement. All new insulators are of the solid core post type as these do not suffer the same modes of failure as pin insulators, and provide a higher level of reliability in polluted environments and lightning prone areas.

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 AAC lines that have historically been used on the Wellington network. Recent incidents have also shown fatigue problems with fittings supporting strain points.

A number of Fargo sleeve type automatic line splices have failed in service. These sleeves were only suitable for a temporary repair but in some cases have 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 are replaced with full tension compression sleeves. Alternatively the span will be reconductored if the joints are not suitably located for replacement.

Figure 6-39 shows the contribution of different component categories towards total overhead line failure SAIDI for the period 1 April 2012 to 31 March 2015. Conductor related failures contributed an average of only 3.5 SAIDI minutes per year out of an average overhead asset failure SAIDI of 8 minutes.

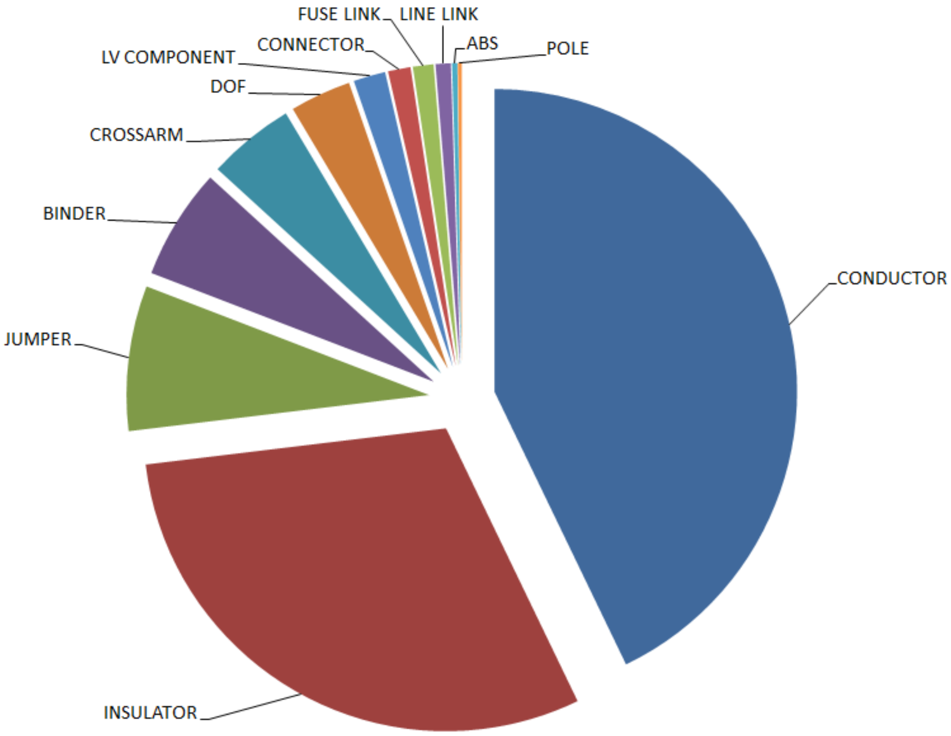


Figure 6-39 Relative SAIDI Impact of Overhead Line Component Failure (2012-2015)

Renewal and Refurbishment - Poles

Wooden poles that are Deuar tested and fail the serviceability test 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 replacement within three 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. Blue tags are used to identify poles that have a reduced ability to support design loads but a serviceability index greater than 1.0 with these poles to have further engineering investigation within three months. For all pole tag colours the climbing of tagged poles by contractors is prohibited.

Concrete poles are replaced following an unsatisfactory visual inspection. The main replacement criteria are poles with large cracks, structural defects, spalling or loss of concrete mass. The severity of the defects determines whether the pole is given a red or yellow tag for replacement within three and 12 months respectively.

All replacement poles are concrete except where the location requires the use of timber for weight, access constraints or loading design. 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. Cranes are used where practicable but have limited reach in some areas of Wellington. Wellington Electricity does not normally use helicopters in erecting poles due to the cost and the need to evacuate residents around the pole location. Sectional steel poles and composite poles are currently being trialled as a possible alternative to softwood poles in hand-carry situations.

<u>Renewal and Refurbishment – Lines</u>

Since 2009, Wellington Electricity has invested in renewal of overhead lines in areas that have particularly high SAIDI and SAIFI or to address public safety concerns. Areas of Newlands, Johnsonville and Korokoro have been progressively reconductored, and have had all the line hardware, crossarms and poor condition poles replaced. These feeders have had a significant improvement in performance since this work was completed.

It is expected that a general programme of conductor replacement, targeting conductors based on age, type and location, will be required from 2021 onwards.

The following overhead asset renewal and reliability projects are planned for 2016:

Pauatahanui – Mana 33kV Rebuild – 2016	
Driver: Asset Integrity **Estimated cost:** $1,000,000	The Pauatahanui-Mana 33kV overhead circuit crosses the Pauatahanui wetland. A number of poles in this area require replacement however a lack of vehicle access and the environmental sensitivity of the area makes this impractical. A project has been initiated to investigate alternative routes, for construction of a replacement line to be constructed during 2016.

Karori 2 Overhead Line Rebuild – Stage 4 – 2016	
Driver: Asset Integrity **Estimated cost:** $150,000	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 with dense vegetation, making access difficult. The fourth stage of nine will occur during 2016, and involves reconductoring 1.4km of 11kV to address reliability concerns arising from hardware condition. Five further stages of this project are planned for the period from 2017 to 2021 with an average annual budget of $150,000.

Ngauranga 7 – Stage 1 – 2016	
Driver: Asset Integrity **Estimated cost:** $190,000	A number of faults during 2014 and 2015 occurred in the overhead section of the Ngauranga 7 feeder in Newlands. These areas have been targeted for replacement of crossarms and insulators, and the reconductoring of 20 spans of 11kV.

South Makara Overhead Line Refurbishment– Stage 2 – 2016	
Driver: Asset Integrity **Estimated cost:** $150,000	South Makara is supplied from the Karori 2 feeder, but was outside of the initial scope of the rebuild, that has been planned to target declining reliability performance. Since the Karori 2 project has commenced, South Makara has begun to experience a similar decline in performance. The scope of this refurbishment is to complete the replacement of pin insulators with line posts, the replacement of existing strain insulators and the replacement of poles, crossarms and transformers that are in poor condition.

Tawa 11 – 2016	
Driver: Asset Integrity **Estimated cost:** $180,000	The Horokiwi area on the Tawa 11 feeder has been subject to poor performance in recent years due to its exposed location and high levels of vegetation. A project in 2015 took steps through the addition of auto-reclose and SCADA control of the circuit breaker that protects the line and a general refurbishment of the line will occur in 2016. This will include consideration of the use of CCT covered conductor through the area most susceptible to vegetation contact, as well as the remediation of all defects in the area.

Wainuiomata Coast Road Line Rebuild – Stage 4 – 2016	
Driver: Asset Integrity **Estimated cost:** $165,000	The Wainuiomata Coast Road area runs south from Wainuiomata towards Baring Head. This has traditionally been a poorly performing feeder on the Wellington Electricity network due to the severe weather it experiences, and has been targeted for progressive upgrade to improve its reliability. The scope of this work is the replacement of pin insulators with line posts, and the replacement of poles and crossarms that are in poor condition. Six further stages of this project are planned for the period from 2017 to 2022, with an average annual budget of $200,000.

Wainuiomata 7 – Urban Area – 2016	
Driver: Asset Integrity **Estimated cost:** $300,000	The urban area of Wainuiomata Coast Road area runs south from Wainuiomata zone substation towards Coast Road. Previous work has targeted the rural area of the feeder, however during 2015 a number of faults occurred in the urban area. Resolving reliability issues at the front end of the feeder will have a significant impact on the overall level of service provided to customers. The scope of this work is the replacement of pin insulators with line posts, and the replacement of poles and crossarms that are in poor condition.

6.5.3.4 Expenditure Summary for Overhead Lines

Figure 6-40 details the expected expenditure on overhead lines by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Pauatahanui-Mana 33kV Rebuild	750	0	0	0	0	0	0	0	0	0
Reliability Improvement Projects	1,631	1,232	1,300	863	1,030	900	919	963	969	1,100
Pole Replacement Programme	6,135	5,800	5,495	5,182	5,000	5,000	5,000	5,000	5,000	5,000
Conductor Replacement Programme	0	0	0	0	0	2,000	2,000	2,000	2,000	2,000
Area Rebuild Projects	0	0	0	0	0	900	900	900	900	900
WCCL Pole Programme[21]	600	450	0	0	0	0	0	0	0	0
Reactive Capital Expenditure	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Capital Expenditure Total	**10,116**	**8,482**	**7,795**	**7,045**	**7,030**	**9,800**	**9,819**	**9,863**	**9,869**	**10,000**
Preventative Maintenance	444	441	439	437	434	433	431	429	428	427
Corrective Maintenance	913	832	824	763	764	858	866	874	880	880
Operational Expenditure Total	**1,357**	**1,273**	**1,263**	**1,200**	**1,198**	**1,291**	**1,297**	**1,303**	**1,308**	**1,307**

Figure 6-40 Expenditure on Overhead Lines
($K in constant prices)

6.5.4 Distribution and LV Cables

<u>Fleet Overview</u>

Wellington Electricity's network has a high percentage of underground cables, which has contributed to a historically high level of reliability during weather-related events but does increase the risk of third party strikes during underground construction work.

Wellington CBD is operated in a closed primary ring configuration with short, normally open radial feeders interconnecting neighbouring rings or zone substations. This part of the network uses automatically operating circuit breakers, with differential protection on cables between distribution substations, 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.

Outside the Wellington CBD, the 11kV underground distribution system has normally open interconnections between radial feeders, and feeders are segmented into small switching zones using locally operated ring

[21] Capital expenditure associated with Wellington Electricity assets attached to WCCL poles that are being replaced. The potential impact of Wellington Electricity purchasing WCCL poles post 2017 has not yet been assessed.

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.

Category	Quantity
11kV cable (incl. risers)	1,162km
Low Voltage cable (incl. risers)	1,657km
Streetlight cable	1,087km

Figure 6-41 Summary of Distribution Cables

Approximately 90% of the underground 11kV cables are PILC and PIAS and the remaining 10% are newer XLPE insulated cables. The majority of low voltage cables are PILC or PVC insulated and a much smaller number are newer XLPE insulated cables.

An age profile of distribution cables of both voltages is shown in Figure 6-42.

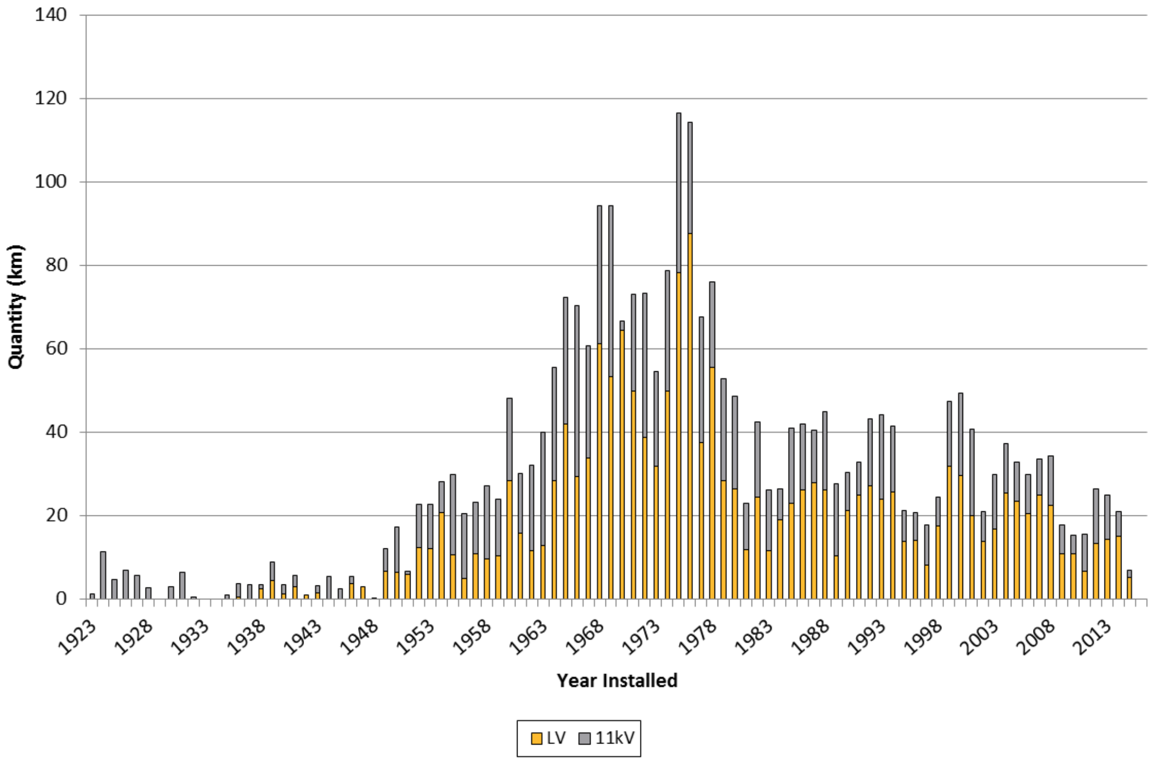


Figure 6-42 Age Profile of Distribution Cables

Maintenance Activities

Maintenance of the underground distribution cable network is limited to visual inspection and thermal imaging of cable terminations. Cables are operated to failure and then either repaired or sections replaced. A proactive maintenance regime is not cost effective, given the network is generally designed so that supply can be maintained while cable repairs are undertaken. Cables are replaced when their condition has deteriorated to the point where repair is not considered economic.

Distribution Cable Condition

In 2015 there were 24 cable, cable joint and termination failures at 11kV and above. Underground cables usually have a long life and high reliability as they are not subjected to environmental hazards however, as these cables age and reach their end of life, performance is seen to decrease. External influences such as third party strikes, inadvertent overloading, or even rapid increases in load within normal ratings can reduce the service life of a cable. Some instances of failure are due to workmanship on newer joints and terminations (which can be addressed through training and education), whilst others are due to age, environment or external strikes (which are less controllable).

Renewal and Refurbishment

The decision to replace rather than repair a cable is based on a combination of fault history and frequency, together with the results of tests undertaken after earlier cable fault repairs. An annual budget allowance is made for cable replacement, targeted at cables exhibiting high fault rates or showing poor test results following a repair. Recent issues highlight the effect of fault stresses on older joints and the need to overlay sections of cables due to repeat joint failures. The small numbers of natural polyurethane insulated cables show high failure rates and this type of cable is therefore more likely to be replaced following a cable fault. An allowance is made each year in the CAPEX programme for cable replacement based upon historic trends and known defects and this allowance is expected to ramp up towards the end of the planning period.

Cable termination replacement is driven by visual inspection when signs of discharge or significant compound leaks are found 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.

6.5.4.1 Expenditure Summary for Distribution and LV Cable

Figure 6-43 details the expected expenditure on distribution and LV cable by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Asset Replacement and Renewal Capex	400	400	400	400	800	1500	2000	2500	3000	3500
Reactive Capital Expenditure	715	855	894	790	844	936	1,030	1,126	1,224	1,323
Capital Expenditure Total	**1,115**	**1,255**	**1,294**	**1,190**	**1,644**	**2,436**	**3,030**	**3,626**	**4,224**	**4,823**
Corrective Maintenance	163	169	175	181	187	194	200	207	215	222
Operational Expenditure Total	**163**	**169**	**175**	**181**	**187**	**194**	**200**	**207**	**215**	**222**

Figure 6-43 Expenditure on Distribution and LV Cable ($K in constant prices)

6.5.5 Distribution Substations

6.5.5.1 Distribution Transformers

Fleet Overview

Of the distribution transformer population, 58% are ground mounted and the remaining 42% are pole mounted. The pole mounted units are installed on single and double pole structures and are predominantly three phase units rated between 10 and 200kVA. The ground-mounted units are three 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 an in-service failure. 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 sea salt spray, a transformer will not reach this age due to corrosion. The age profile of distribution transformers is shown in Figure 6-44.

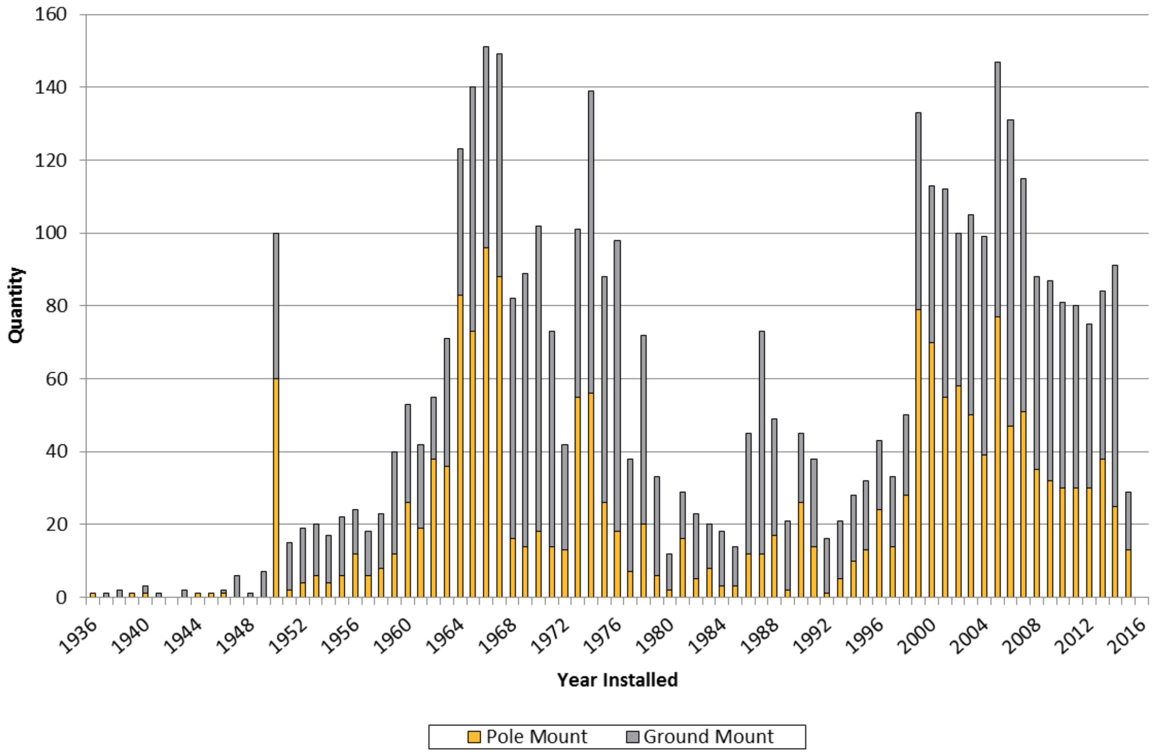


Figure 6-44 Age Profile of Distribution Transformers

In addition to pole and integral pad mount berm substations, Wellington Electricity owns 478 indoor substation kiosks and occupies a further 688 sites that are customer owned (typically of masonry or block construction or outdoor enclosures). A summary of Wellington Electricity's distribution transformers and substations is shown in Figure 6-45.

Category	Quantity
Distribution transformers	4,348
Wellington Electricity owned substations	3,616
Customer owned substations	688
Distribution substations – Total	**4,304**

Figure 6-45 Summary of Distribution Transformers and Substations

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	General programme of ground and building maintenance for distribution substations.	Ongoing
Fire Alarm Test	Inspect and test passive fire alarm systems.	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 Distribution Transformers

Distribution Transformer Condition

Figure 6-47 shows the health-criticality matrix of Wellington Electricity's fleet of distribution transformers, including both pole- and ground-mounted units. Distribution transformer asset health is comprised of type issues and the unit's condition ranking, while asset criticality is determined by the number and type of customers connected to the transformer.

		Lowest Impact		Asset Criticality				Highest Impact
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
Asset Health	1.5	1	1	2				
	2.0	128	1	85	3	104		
	2.5	5		3		15		
	3.0	953	288	996	99	474		
	4.0	190	225	290	84	38		
Best Health	5.0	115	52	166	16	14		

Figure 6-47 Distribution Transformer Health-Criticality Matrix

Type issues that have been identified with the fleet of distribution transformers are as follows.

Internal Bushing Transformers

Ground-mounted transformers manufactured by Bonar Long, Bryce and ASEA were installed between 1946 and 1980, with 58 such units currently in service. Many of these transformers have internal 11kV bushings, with cambric cables being terminated inside the transformer tank. This does not pose a problem during normal operation, however if the switchgear at the site requires replacement, then the cables and hence the transformer will also need to be replaced.

Pole-mounted Transformers

Analysis of transformer faults indicate that transformers between 25 and 40 years old have been failing at a greater rate than those between 40 and 60 years. Pole-mounted transformer failure rates by age are illustrated in Figure 6-48. It is suspected that these premature failures may be lightning-related, potentially due to modern transformers having more optimised designs than older units. Given the low cost of pole-mounted transformers, no action is planned at this stage to address the issue.

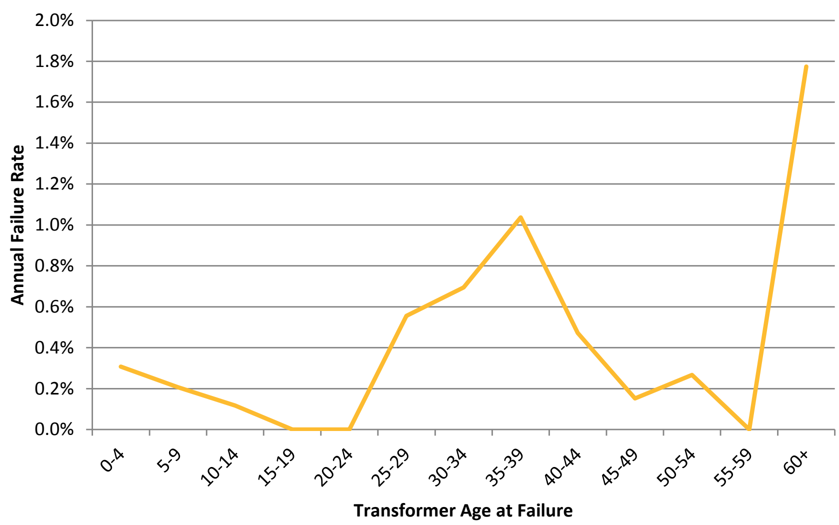


Figure 6-48 Pole-mounted Transformer Failure Rates, 2011-2015

Renewal and Refurbishment

If a distribution transformer is found to be in an unsatisfactory condition during its regular inspection, it is programmed for corrective maintenance or replacement. In-service transformer failure is rare and is investigated to determine the cause. This assessment determines if the unit is repaired, refurbished, or scraped depending on cost 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 are 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 forecast, however it is undertaken on an as-needed 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 needed. Examples include distribution earthing, substation canopies and kiosk building components (such as weather tightness improvements). Some renewals may be costly and time consuming as a large number of berm substations in the Hutt Valley area are an integral substation unit manufactured during the 1970s and 1980s by the likes of Tolley Industries. Replacement of these units requires complete foundation replacement and extensive cable works. Consideration was given to developing a compatible replacement, and a prototype unit installed, however it was found that the reduced civil cost was offset by the additional cost for purchasing a specialised transformer rather than a standard design.

Wellington Electricity uses canopy type substations with independent components (LV switchgear, HV switchgear and transformer under an arc-fault rated metal canopy) for new installations where practicable, however cost and space constraints often mean integral substations are still 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.

Expenditure Summary for Distribution Substations

Figure 6-49 details the expected expenditure on distribution substations by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Seismic Strengthening	414	570	463	1,016	1,193	1,288	1,336	0	0	0
Earthing Upgrades	300	300	300	300	300	300	300	300	300	300
Lock Replacement	200	200	200	200	200	200	200	200	200	200
Asset Replacement and Renewal Capex	2,375	1,375	1,500	1,500	1,625	2,000	2,500	2,500	2,500	2,500
Reactive Capital Expenditure	500	500	500	500	500	500	500	500	500	500
Capital Expenditure Total	**3,789**	**2,945**	**2,963**	**3,516**	**3,818**	**4,288**	**4,836**	**3,500**	**3,500**	**3,500**
Preventative Maintenance	435	435	435	435	435	435	435	435	435	435
Corrective Maintenance	960	872	938	940	937	980	977	974	971	968
Operational Expenditure Total	**1,395**	**1,307**	**1,373**	**1,375**	**1,372**	**1,415**	**1,412**	**1,409**	**1,406**	**1,403**

Figure 6-49 Expenditure on Distribution Substations
($K in constant prices)

6.5.5.2 Ground Mounted Distribution Switchgear

Fleet Overview

This section covers ring main units and switching equipment that are often installed outdoors. It does not include zone substation circuit breakers, which are covered in Section 6.5.2.3. There are 1,296 distribution circuit breakers and 2,265 other ground-mounted switches in the Wellington Electricity network.

11kV circuit breakers are used in the 11kV distribution network to increase the reliability of supply in priority areas such as in and around the CBD. Other ground-mounted switches include fuse switches for the protection of distribution transformers, and load break switches to allow isolation and reconfiguration of components on the network, often with multiple switches combined in a single ring main unit.

The age profiles of distribution circuit breakers and ground-mounted switchgear are shown in Figure 6-50 and Figure 6-51.

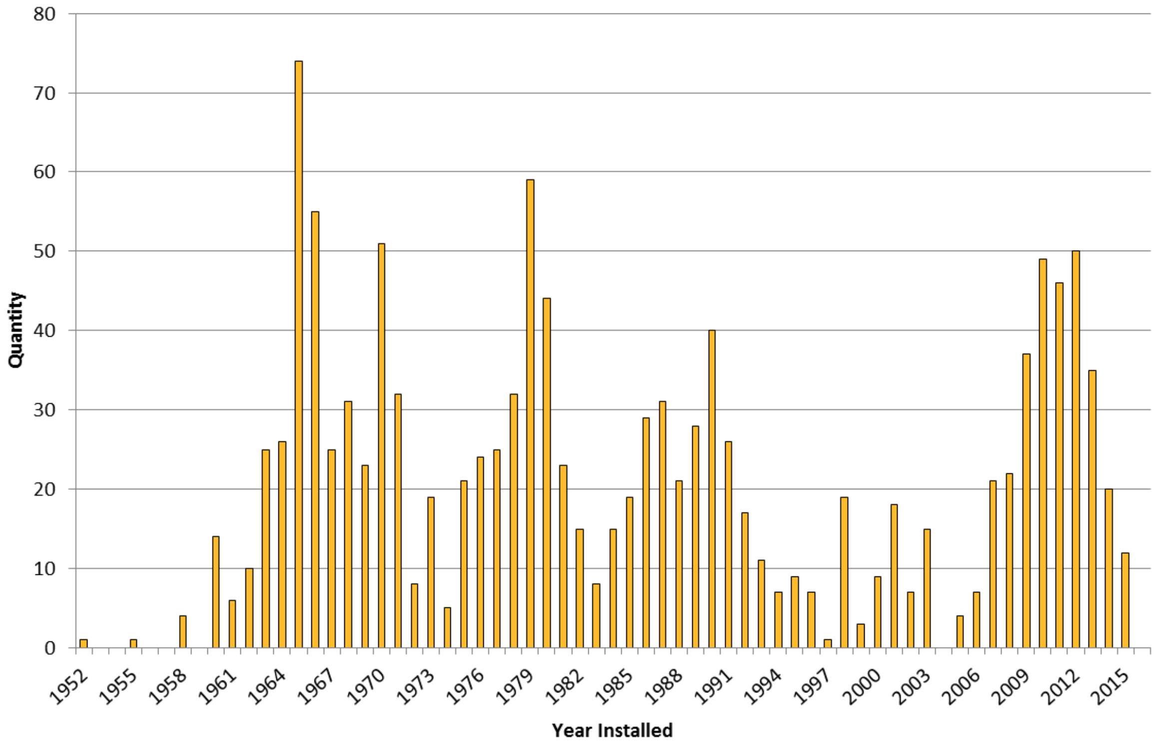


Figure 6-50 Age Profile for Distribution Circuit Breakers

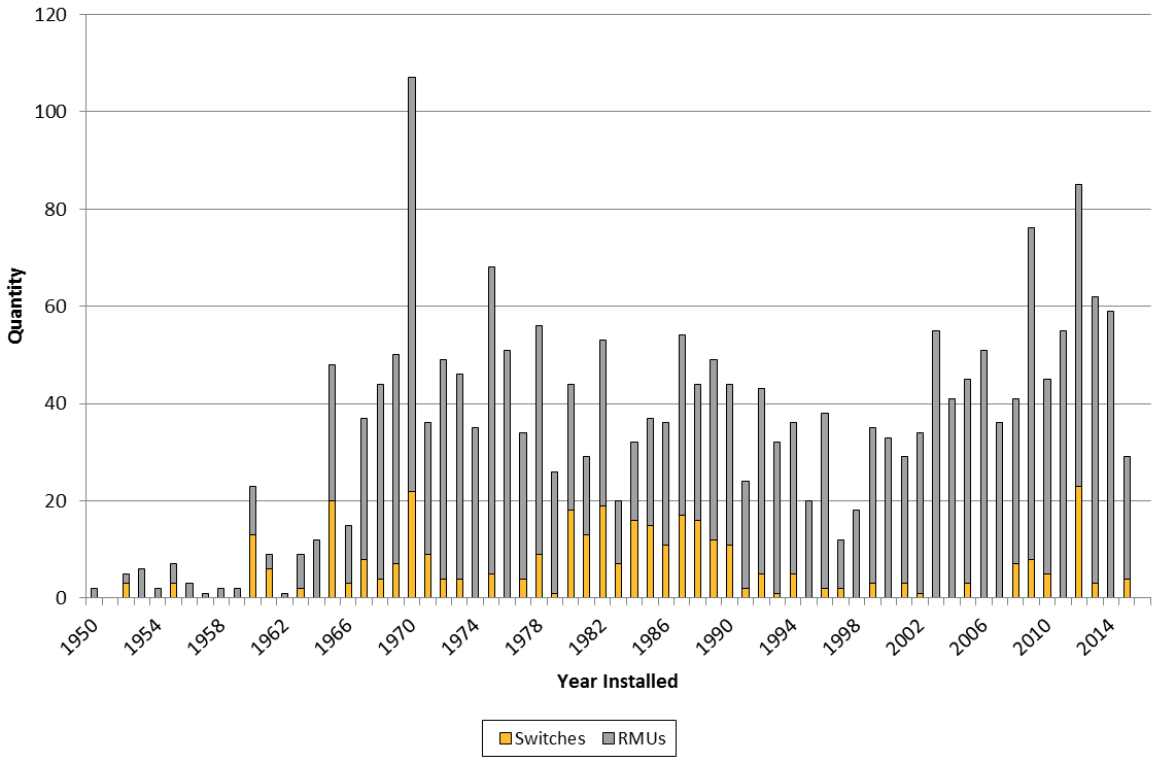


Figure 6-51 Age Profile of Other Ground Mounted Distribution Switchgear

The average age of circuit breakers in the network is around 31 years, while the average age of the ground mounted distribution switchgear is 26 years. A summary of circuit breakers and ground mounted distribution switchgear, of both stand-alone and ring main unit types, is shown in Figure 6-52 and Figure 6-53.

Category	Quantity
Distribution Circuit Breakers	1,296
Oil Insulated Switches	307
Oil Insulated RMUs	244
SF_6 Insulated Switches	52
SF_6 Insulated RMUs	604
Solid Insulated RMUs	1,058

Figure 6-52 Summary of Ground Mounted Distribution Switchgear

Manufacturer	Breaker Type	Quantity
ABB	SF_6	21
AEI	Oil	77
BTH	Oil	45
Crompton Parkinson	Oil	1
GEC/Alstom	Oil	61
Hawker Siddeley	Vacuum	21
Merlin Gerin / Schneider	SF_6	271
Reyrolle	Oil	675
	Vacuum	45
South Wales	SF_6	37
Statter	Oil	34[22]
Yorkshire	Oil	8
Total		**1,296**

Figure 6-53 Summary of Distribution Circuit Breakers by Manufacturer

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on ground mounted distribution switchgear and associated equipment:

[22] This is for circuit breakers only and excludes the HV switches and ring main units.

Activity	Description	Frequency
Visual Inspection of Switchgear	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
Switchgear Maintenance (Magnefix)	Clean and maintain Magnefix unit, inspect and replace link caps as required, test fuses, check terminations where possible.	5 yearly
Circuit Breaker Maintenance (Oil CB)	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	5 yearly
Switch 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
Circuit Breaker Maintenance (Vacuum or Gas CB)	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	5 yearly
Switch 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
11kV Switchboard Major Maintenance	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	10 yearly

Figure 6-54 Inspection and Routine Maintenance Schedule for Distribution Switchgear

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 but, on occasion, a unit requires replacement when the condition is unacceptable. Common condition issues experienced include mechanical wear of both the enclosure/body as well as operating mechanisms, electrical discharge issues or poor oil condition and insulation levels.

Figure 6-55 shows the health-criticality matrix of Wellington Electricity's fleet of ground-mounted distribution switchgear. Distribution switchgear asset health is comprised of type issues and the unit's condition ranking, while asset criticality is determined by the 11kV feeder that the unit is connected to.

	Asset Health	Lowest Impact		Asset Criticality			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0	20	21	68	11			
	1.5	30	36	183	30	2	3	
	2.0	2	34	112	9	26	44	
	2.5	40	46	221	37	225	170	
	3.0	83	178	629	151	415	221	
	4.0	33	112	205	97	19	7	
Best Health	5.0	4	5	12	9	1	10	

Figure 6-55 Distribution Switchgear Health-Criticality Matrix

Aside from issues relating to Reyrolle LMT switchgear as noted in Section 6.5.2.3, other specific condition issues are:

Solid Insulation Units - Magnefix/Krone

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. It is believed that the “Figure 8” connectors on some older units (typically installed between 1968 and 1975) fail under heavy loads due to heating and thermo-mechanical cycling problems. The failures all occurred on residential feeders with recent load growth and 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 heat shrink terminations, providing the unit does not need replacement due to age, overall condition, or operational factors. During 2015, Wellington Electricity replaced the terminations on 45 units, prioritised by the lowest levels of grease in the termination. Aside from the connector issue, these units are not at end of life and replacement of the terminations is considered an effective and efficient maintenance strategy.

Yorkshire SO-HI

Yorkshire SO-HI circuit breakers were installed during the 1970s and 1980s in indoor kiosk type substations. SO-HI switchgear has a history of failing in service, and in 2011 Wellington Electricity initiated a replacement programme for SO-HI units, commencing with sites identified as having a high consequence of failure. Replacement is currently underway for the last SO-HI units, which will complete the project in 2016.

Long and Crawford

As at October 2015, there are 48 Long and Crawford ring main units in service, installed between 1960 and 1996. These are installed in outdoor cage substations subject to harsh environments. Other networks have experienced catastrophic failures of Long and Crawford fuse switches. Wellington Electricity has imposed operational restrictions on Long and Crawford fuse switches to prevent the fuse compartments being opened while the switchgear is alive, and a programme to replace Long and Crawford units is commencing in 2016, for completion by 2022.

Statter

As at October 2015, there are 77 sites with Statter switchgear, with 182 units in service including circuit breakers, oil switches and fuse switches, installed between 1955 and 1991.

In recent years, there have been instances where Statter switchgear has failed to operate requiring operating restrictions to be in place until the unit is repaired or replaced. Statter switchgear is at the end of its 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 in 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.

Renewal and Refurbishment

HV Distribution Switchgear (Ground Mounted)

Note – This section excludes zone substation circuit breakers, which are discussed in Section 6.5.2.3.

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. In addition to previously identified programmes for replacing specific switchgear, Wellington Electricity has an ongoing refurbishment and replacement programme for other ground mounted distribution switchgear with an annual budget of $1.0 million.

Oil insulated switchgear is no longer installed with vacuum or gas (SF6) insulated types now being used. When any switchgear device fails, the reason for the failure is studied and cost benefit analysis undertaken to determine whether to repair, refurbish, replace, or decommission the device. The maintenance policies for other devices of the same type are also reviewed. As noted above, there are several types of ring main switch with identified issues around age, condition and known operational issues. These may be replaced based on the risk assessment for that type.

Low Voltage Distribution Switchgear (Substation)

Low voltage distribution switchgear and fusing is maintained as part of routine substation maintenance and any issues arising are dealt with at the time. The Wellington City area has a large number of open LV distribution boards in substations and a safety programme to cover these with clear Perspex covers has been completed.

In early 2016 a safety alert was issued to contractors prohibiting live work between the transformer bushings and the low voltage busbars, and work in situations where items may contact live busbars. This is being followed up by further work to detail an arc flash policy in 2016.

The overall performance of LV distribution switchgear and fusing is good and there are no programmes underway to replace this equipment.

Expenditure Summary for Ground-mounted Switchgear

Figure 6-56 details the expected expenditure on ground-mounted switchgear by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Long and Crawford Replacement Programme	570	650	690	630	630	473	0	0	0	0
Statter Replacement Programme	1,500	1,500	1,500	1,500	1,125	0	0	0	0	0
Other Asset Replacement and Renewal Capex	1,037	725	310	245	245	1,500	2,500	3,000	3,000	3,000
Reactive Capital Expenditure	650	650	650	650	650	650	650	650	650	650
Capital Expenditure Total	**3,757**	**3,525**	**3,150**	**3,025**	**2,650**	**2,623**	**3,150**	**3,650**	**3,650**	**3,650**
Preventative Maintenance	540	540	540	540	540	540	540	540	540	540
Corrective Maintenance	560	553	545	538	530	523	516	509	502	495
Operational Expenditure Total	**1,100**	**1,093**	**1,085**	**1,078**	**1,070**	**1,063**	**1,056**	**1,049**	**1,042**	**1,035**

Figure 6-56 Expenditure on Ground-mounted Switchgear ($K in constant prices)

6.5.5.3 Low Voltage Pits and Pillars

Fleet Overview

Pillars and pits provide the point for the connection of customer service cables to the Wellington Electricity underground LV 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 396 link pillars and pits in service on Wellington Electricity's 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 in Figure 6-57.

Type	Quantity
Customer service pillar	14,690
Customer service pit	1,771
Link pillars and pits	396
Total	**16,857**

Figure 6-57 Summary of LV Pillars and Pits

An age profile of pillars and pits is shown in Figure 6-58. Approximately 6,400 pits and pillars have unknown ages, and these are not included in the age profile.

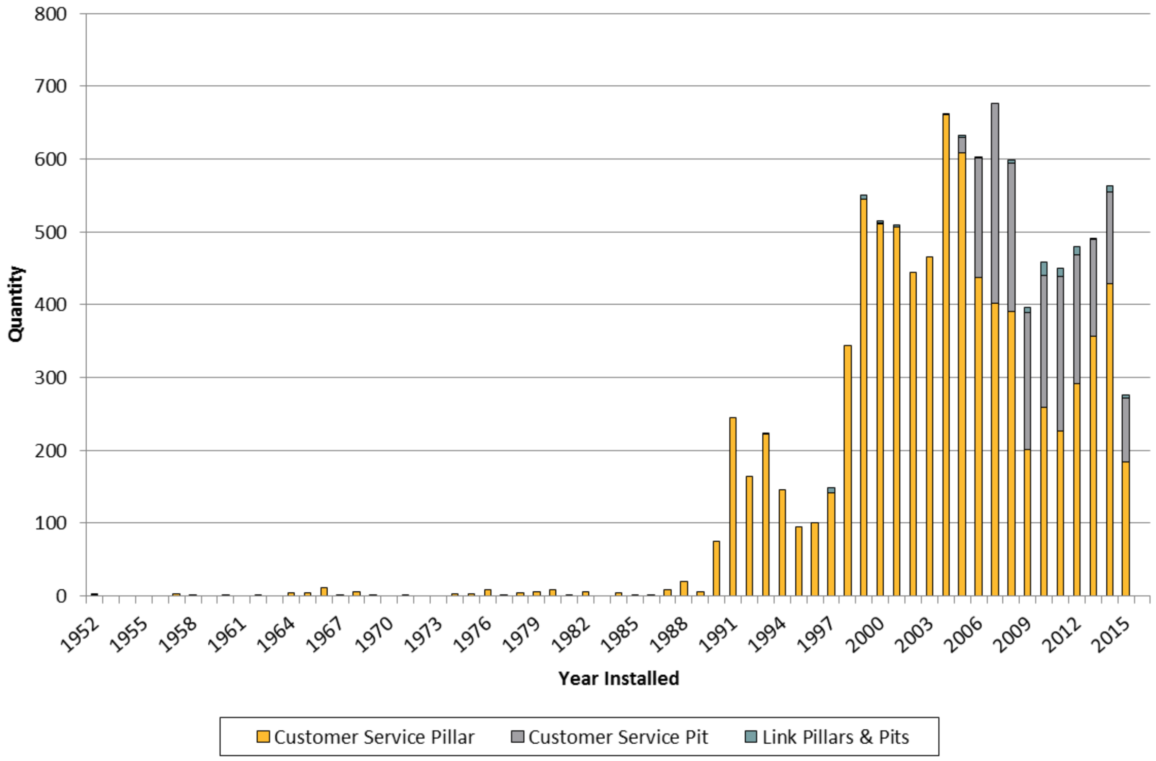


Figure 6-58 Age Profile of Pillars and Pits

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on low voltage pits and pillars, for either consumer service connection and fusing or network LV 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 6-59 Inspection and Routine Maintenance Schedule for LV Pits and Pillars

Wellington Electricity includes a loop impedance test to check the condition of the connections from the fuses to the source in its underground pillars inspection regime. Where practical, damaged pillars are repaired but otherwise a new pillar or a pit is installed.

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, particularly under-veranda service connection boxes in older commercial areas.

There is an ongoing replacement of underground link boxes around Wellington City driven by the condition of some of these assets. The link boxes are either jointed through, where the functionality is no longer required, or replaced entirely to provide the same functionality. Link boxes will be replaced following an unsatisfactory inspection outcome, and it is expected that fewer than 10 will require replacement every year.

Expenditure Summary for Low Voltage Pits and Pillars

Figure 6-60 details the expected expenditure on low voltage pits and pillars by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Asset Replacement and Renewal Capex	150	150	150	150	150	150	150	150	150	150
Reactive Capital Expenditure	150	150	150	150	150	150	150	150	150	150
Capital Expenditure Total	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
Preventative Maintenance	60	60	60	60	60	60	60	60	60	60
Corrective Maintenance	50	50	50	50	50	50	50	50	50	50
Operational Expenditure Total	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**

Figure 6-60 Expenditure on Low Voltage Pits and Pillars ($K in constant prices)

6.5.6 Pole-mounted Distribution Switchgear

6.5.6.1 Reclosers and Gas Switches

Fleet Overview

Automatic circuit reclosers are pole mounted circuit breakers that provide protection for the rural 11kV overhead network. The majority of the 18 reclosers on the network are vacuum models with electronic controllers, with only eight being older hydraulic types. The individual types of auto-reclosers are shown in the Figure 6-61.

Manufacturer	Insulation	Model	Quantity
G&W	Solid/Vacuum	ViperS	10
Reyrolle	Oil	OYT	5
McGraw-Edison	Oil	KFE	3
Total			**18**

Figure 6-61 Summary of Recloser Types

The age profile of Wellington Electricity's reclosers is shown in Figure 6-62.

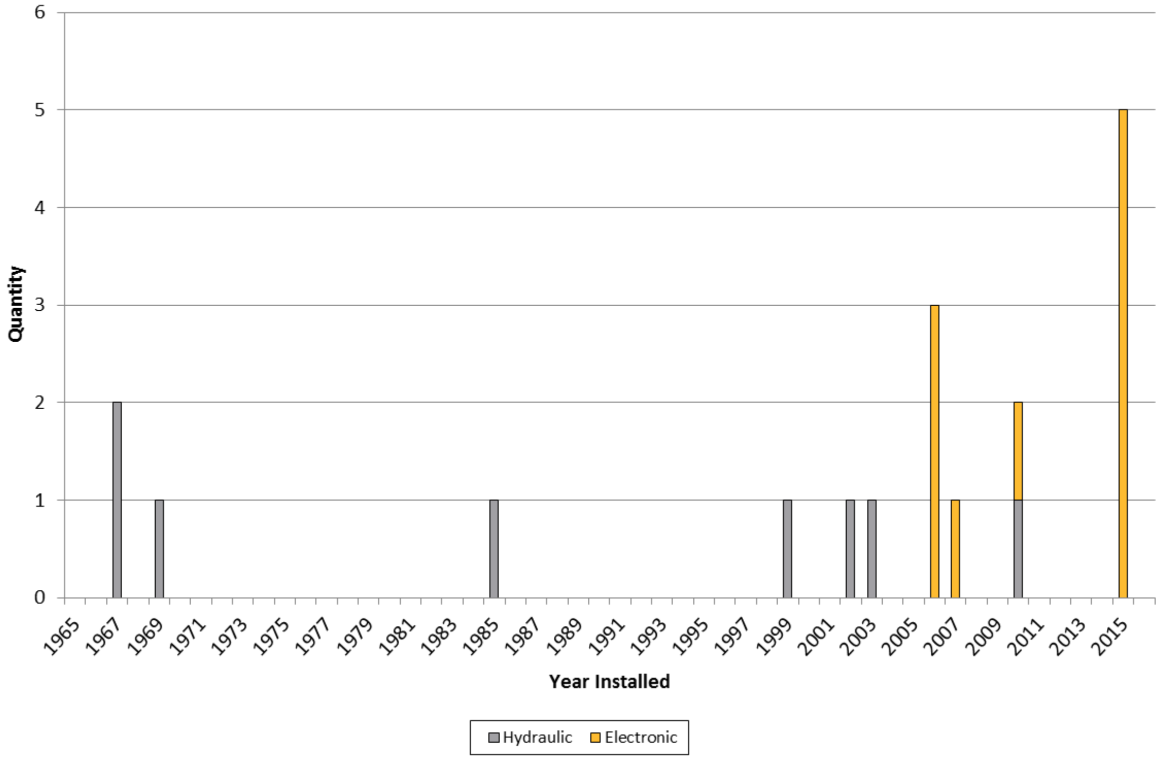


Figure 6-62 Age Profile of Reclosers

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on reclosers:

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 Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication.	Annually
Recloser 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 6-63 Inspection and Routine Maintenance Schedule for Auto Reclosers

Renewal and Refurbishment

One major contributor towards network performance in rural areas is having reliable and appropriately placed reclosers in service. The majority of the units in service are relatively new, in good condition and performing as expected, however all types of hydraulic recloser have experienced failures in recent years. Refurbishment has proven ineffective at returning failed hydraulic reclosers to effective service, and units are instead replaced with electronic reclosers on failure.

A replacement programme commenced in 2013, with the intention of phasing out hydraulic reclosers from service by 2020. A higher than expected rate of failure of hydraulic reclosers resulted in more units being replaced in 2015 than anticipated, with the programme now expected to be completed during 2018. Units are prioritised for replacement on the basis of performance history, other defects, and the potential SAIDI impact of future failures.

Expenditure Summary for Reclosers

Figure 6-64 details the expected expenditure on reclosers by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Asset Replacement and Renewal Capex	360	440	240	0	0	0	0	0	0	0
Capital Expenditure Total	**360**	**440**	**240**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Preventative Maintenance	9	8	8	7	7	7	7	7	7	7
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**19**	**18**	**18**	**17**	**17**	**17**	**17**	**17**	**17**	**17**

Figure 6-64 Expenditure on Reclosers
($K in constant prices)

6.5.6.2 Overhead Switches, Links and Fuses

Fleet Overview

Overhead switchgear is used for breaking the overhead network into sections, and providing protection to pole mounted distribution transformers, and cables at overhead to underground transition points. A summary of the quantities of different categories of overhead switches are shown in Figure 6-65.

Category	Quantity
Gas Switches	73
Air Break Switches	277
Knife Links	165
Dropout Fuses	2,080
Dropout Sectionalisers	8
Total	**2,603**

Figure 6-65 Summary of Pole Mounted Distribution Switchgear

The age profiles of these devices are shown in Figure 6-66.

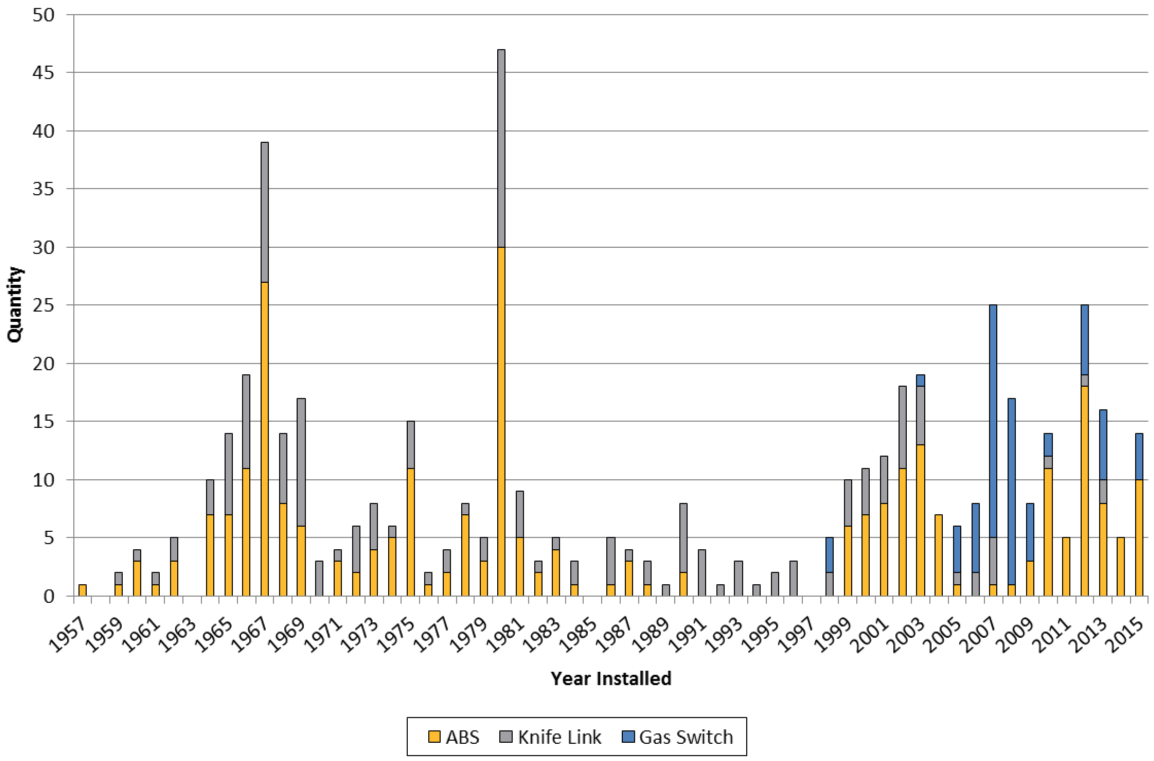


Figure 6-66 Age Profile of Overhead Switchgear and Devices

Maintenance Activities

The following routine planned inspection, testing and maintenance activities that are undertaken on overhead switches, links and fuses are shown in Figure 6-67.

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
Remote Controlled Switch Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with NCR 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 6-67 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 risk 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 back-feeding from either side.

Condition of Overhead Switches, Links and Fuses

Generally, the condition of overhead equipment on the 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. This is a result of the use of different metals causing the pivot point on the fuse holder to seize and prevent 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 three years this has not been a major issue and therefore replacement currently only occurs as required.

The coastal environment around Wellington causes accelerated corrosion on galvanised overhead equipment components and, where possible, stainless steel fittings are used as they have proven to provide a longer component service life. These high quality components come at an increased cost.

Renewal and Refurbishment

There is no structured programme to replace overhead switchgear or devices, and they are generally not cost-effective to refurbish. 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 cross arm replacements undertaken over recent years, a large number of overhead switches have now been replaced. Replacement generally occurs following a poor condition assessment result from the routine inspections, or at the time of pole or cross arm replacement if the condition of the switch justifies this at that time.

Expenditure Summary for Overhead Switchgear

Figure 6-68 details the expected expenditure on overhead switchgear by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Reactive Capital Expenditure	200	200	200	200	200	200	200	200	200	200
Capital Expenditure Total	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Preventative Maintenance	120	120	120	120	120	120	120	120	120	120
Corrective Maintenance	120	121	122	124	125	126	127	129	130	131
Operational Expenditure Total	**240**	**241**	**242**	**244**	**245**	**246**	**247**	**249**	**250**	**251**

Figure 6-68 Expenditure on Overhead Switchgear
($K in constant prices)

6.5.7 Other System Fixed Assets

6.5.7.1 Substation DC Systems

Fleet Overview

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 DC voltages: 24, 30, 36, 48, and 110V, largely for historical reasons, however, it has standardised on 24V for all new or replacement installations.

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 6-69 Inspection and Routine Maintenance Schedule for Zone Substation Battery Banks

Valve regulated lead acid 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).

Battery and Charger Condition

The overall condition of the battery population is very good. Battery chargers are also generally in good condition. Many have SCADA supervision so the NCR is notified if the charger has failed. Given the low value and high repair cost of battery chargers, they are repaired only where it is clearly economic. Generally, the chargers are at the end of their design life at the time of failure so replacement is readily justified.

Battery Replacement

Wellington Electricity has a total of 527 battery banks across 279 sites. Batteries are a critical system for substation operation, but are low cost items. Wellington Electricity's policy is that all batteries are replaced at 80% of their design life rather than implementing an extensive testing regime. For a number of sites with higher ampere-hour demand, 10-year life batteries are available. For smaller sites, or communications batteries where the demand is lower, batteries are installed with 5-year lives. As part of primary plant replacements, Wellington Electricity is standardising the voltages used for switchgear operation as well as communications equipment.

Expenditure Summary for Substation Batteries

Figure 6-70 details the expected expenditure on substation batteries by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Asset Replacement and Renewal Capex	148	173	478	349	266	300	300	300	300	300
Capital Expenditure Total	**148**	**173**	**478**	**349**	**266**	**300**	**300**	**300**	**300**	**300**
Preventative Maintenance	20	20	20	20	20	20	20	20	20	20
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**

**Figure 6-70 Expenditure on Substation Batteries
($K in constant prices)**

6.5.7.2 Substation Protection Relays

Fleet Overview

Secondary protection assets are relays that automatically detect conditions that indicate a potential primary equipment fault and automatically issue control signals to disconnect the faulted equipment. This ensures that the system remains safe and that damage is minimised. Protection assets are also installed to limit the number of consumers affected by an equipment failure.

On the HV system, there are approximately 1400 protection relays in operation. The majority of these are electromechanical devices. The remainder use solid state electronic and microprocessor technology. Relays are generally mounted as part of a substation switchboard and are normally upgraded at the time of switchgear replacement.

On subtransmission circuits, and in the Wellington City area where the network is comprised of closed 11kV rings, protection relays use differential protection where the power entering a circuit is compared with the power output. As a backup on these circuits, and in situations where differential protection is not required (such as radial feeders with normally open points), overcurrent and earth fault (OC/EF) relays are used where circuit currents are measured and a disconnect signal issued if these move outside an expected range.

At distribution level, 11kV fuses are also used for protection of distribution transformers and other equipment. Fuses are used on the LV system for the protection of cables and equipment. Fuses form part of the primary circuit and are not secondary assets.

Automatic Under Frequency Load Shedding (AUFLS) relays are installed at 19 zone substations. These are programmed to trip feeders in the event of the system frequency dropping below certain setpoints, as required by the System Operator rules.

The average age of the protection relays on the Wellington Electricity network is around 40 years with approximately 48% of the protection relays are more than 40 years old.

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.	4 yearly (Zone) 5 yearly (Distribution)

Figure 6-71 Inspection and Routine Maintenance Schedule for Protection Relays

The testing of differential relays (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 in line with 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.

Renewal and Replacement

Generally, all protection relays are in good condition with the exception of PBO electromechanical and Nilstat ITP solid state relays, which have performance and functionality issues. The relay replacement programmes that are in place generally focus on relay condition and coordination with other projects especially for assets such as switchgear and transformers. Rarely does a relay fail in-service and deterioration of relays is identified during routine maintenance testing which may lead to individual relay replacement.

At the time of primary equipment replacement, the opportunity is taken to upgrade associated protection schemes to meet the current standards. To date, electromechanical relays have provided reliable service and are expected to remain in service for the life of the switchgear they control. 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 switchgear life is expected.

The following programmes and projects are included in the asset replacement and maintenance budgets:

- Ongoing replacement of PBO relays in conjunction with switchgear;
- Nilstat overcurrent relays are being replaced. The only remaining units of this type are in the Reyrolle Type C switchboard at Gracefield zone substation and, as this switchboard is planned for replacement commencing in 2017, a separate relay replacement project is not justified;
- Ongoing zone substation and network protection and control upgrades for assets supplied from GXPs, which are coordinated with GXP upgrades planned by Transpower; and
- Ongoing protection and control upgrades across the network as identified by asset condition monitoring.

The Authority is proposing to replace AUFLS with an Extended Reserves scheme. This may require replacement of existing AUFLS relays in order to meet the new requirements, however the timing, technical specifications and funding mechanisms for this are not currently known, and as such this work has not been included in this AMP.

Expenditure Summary for Protection Relays

Figure 6-72 details the expected expenditure on protection relays by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission Relay Replacement Programme	735	450	825	1,035	540	0	0	0	0	100
Other Asset Replacement and Renewal Capex	250	250	250	250	250	450	600	600	600	500
Capital Expenditure Total	**985**	**700**	**1,075**	**1,285**	**790**	**450**	**600**	**600**	**600**	**600**
Preventative Maintenance	130	130	130	130	130	130	130	130	130	130
Corrective Maintenance	15	15	15	15	15	15	15	15	15	15
Operational Expenditure Total	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**	**145**

Figure 6-72 Expenditure on Protection Relays
($K in constant prices)

6.5.7.3 SCADA and Communications Assets

Fleet Overview

The SCADA master station is a GE PowerOn Fusion system, commissioned in early 2016. A legacy Foxboro system has been retained in the short term to provide the automatic load control function until an alternative system is implemented.

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

More specifically, SCADA 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; and
- Transmit local system alarms to the control room for action.

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

The most common communication links are copper pilot and fibre optic cables. Typically the copper pilots are Wellington Electricity owned while some fibre links are under lease agreements.

Wellington Electricity has two NCRs at separate sites, with one set up as a Disaster Recovery site. These sites are interconnected via the Transmission Control Protocol/Internet Protocol (TCP/IP) network.

An age profile of SCADA RTUs is shown in Figure 6-73.

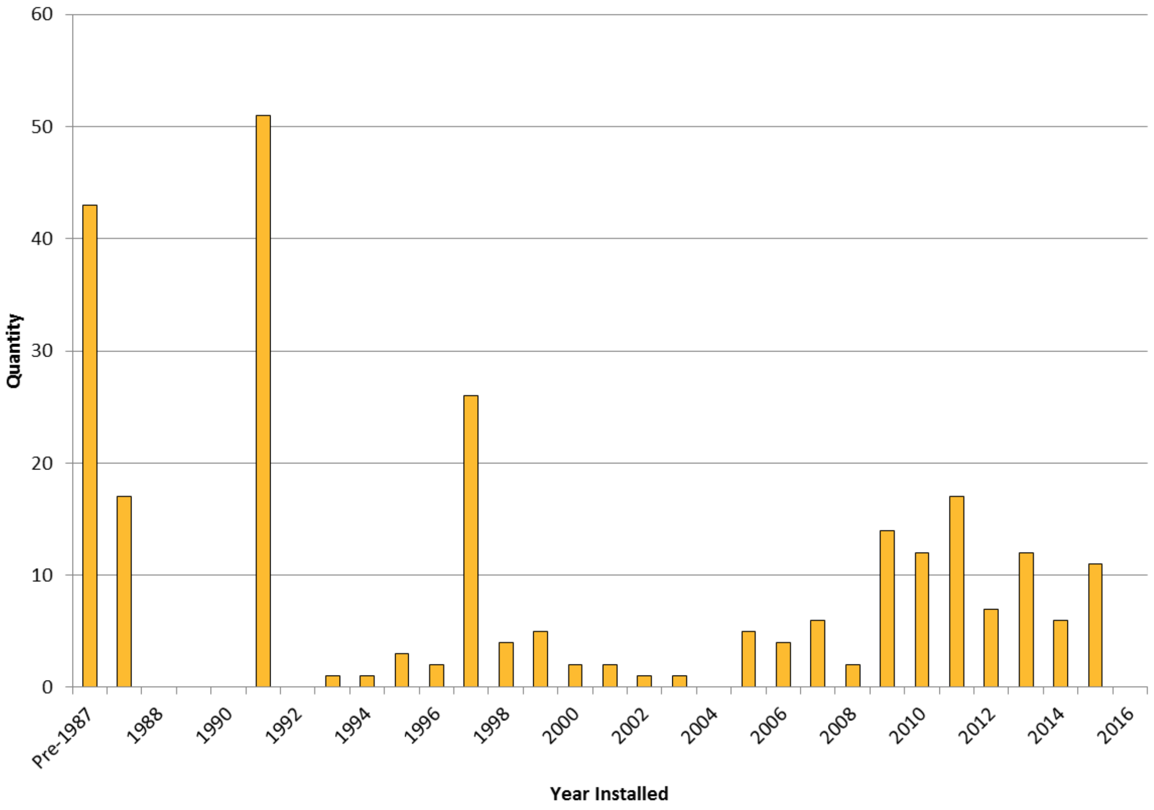


Figure 6-73 Age Profile of SCADA RTUs

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.

There are currently 60 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 located at three sites and the DNP3.0 SCADA master station. These units are at end of life and will be replaced with standard RTUs during 2016.

Maintenance Activities

The SCADA system is generally self-monitoring and there is little preventative maintenance carried out on it apart from planned server and software upgrades and replacement. Master station maintenance is broken into two categories:

(a) Hardware support for the disaster recovery site is provided as required by Wellington based maintenance contractors; and

(b) Software maintenance and support is provided by external service providers.

Existing RTUs are managed on a run to failure strategy. First line maintenance on the system is carried out as required by the Field Service Provider 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 front end processors have Uninterruptible Power Supply (UPS) systems to provide backup supply and there is a UPS system providing supply to the operator terminals in the NCR. This is subject to a maintenance programme provided by the equipment supplier. In addition, these units have their self-diagnostics remotely monitored and dual redundancy of converters and batteries to provide a high level of supply security in the unlikely event of failure.

Condition of SCADA System Components

C225 RTU

There are 16 C225 RTUs in service on the network. Power supply failure is the most common failure mode with around one failure a year. Spares are at a central location and repairs are carried out where possible. These RTUs are being replaced in conjunction with GXP protection upgrades, and the redundant units are then held as spares.

C5 RTU

There are six C5 RTU's in service at very small distribution substations. They are no longer manufactured and are difficult to repair, so as they fail they are interchanged with modern alternatives.

Dataterm RTU

There are three of these still in service on the network, including three at zone substations. 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 at 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 52 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 but replacement occurs in conjunction with substation switchgear replacements, or where a risk is identified in having this type of RTU installed.

Common Alarms

There are 44 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 the NCR of a tripping event. They are prone to failure and there are no spares. On failure, the units are replaced by current technology such as a low cost RC02 RTU which is widely used on the network.

Cisco 2811 Routers

There are 32 Cisco 2811 routers in service, located in distribution substations connected to the TCP/IP network. These devices are no longer supported by the manufacturer and replacement parts cannot be purchased. There are no concerns about the performance of the equipment but where expansion is required, for example the addition of VOIP interface cards, the 2811 router is replaced with its modern equivalent and returned to stock as a spare.

Renewal and Refurbishment

The asset replacement budget provides for the ongoing replacement of obsolete RTUs throughout the network. Obsolete RTUs that may have a significant impact on network reliability are targeted first with priority being given to the zone and major switching substations.

If an RTU at a zone substation or major switching point in the network is adjacent to the existing TCP/IP network, consideration is given to upgrading the equipment to allow TCP/IP connection in order to continuously improve communication system reliability. Furthermore the TCP/IP infrastructure will also allow other substation based equipment (such as security alarms etc.) to efficiently communicate with distant receive devices.

The priority of the substation RTU replacement programme will align with GXP protection upgrade and zone substation switchgear replacement projects. 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 an RTU upgrade will be scheduled when a specific risk is identified. In addition, sites where switchgear is upgraded may also have an RTU upgrade. These are incorporated as part of the switchgear replacement project and the need for an RTU replacement is evaluated on a case-by-case basis.

Copper pilot cables are repaired on failure. When the business case for new digital communication equipment requires a higher level of service, then copper pilot replacement with fibre optic cable is determined on a case by case basis.

Analogue SCADA Radio Replacement

The Network Communications Strategy has identified a risk associated with the age and configuration of the analogue radio network which is used as the communications link for a number of field devices (such as reclosers and remote switches). A review of the existing network, future requirements and potential replacement systems was commenced during 2014, resulting in the recommendation that the system be replaced with a mesh radio network. The cost of replacing the existing network has been estimated at approximately $500,000.

Expenditure Summary for SCADA and Communications Assets

Figure 6-74 details the expected expenditure on SCADA and communications assets by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
RTU Replacement Programme	900	675	900	900	950	825	500	500	500	500
SCADA Radio Replacement Programme	80	285	135	0	0	0	0	0	0	0
Reactive Capital Expenditure	100	100	100	100	100	100	100	100	100	100
Capital Expenditure Total	**1,080**	**1,060**	**1,135**	**1,000**	**1,050**	**925**	**600**	**600**	**600**	**600**
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**

Figure 6-74 Expenditure on SCADA and Communications Assets ($K in constant prices)

6.5.8 Other Network Assets

6.5.8.1 Metering

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

Check meters 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. MDIs are used for operational and planning purposes only and are considered part of the distribution substation. In future, there may be benefits from accessing smart metering data from consumer premises to feed into the network planning and asset management processes, as well as for real time monitoring of the performance of the low voltage network.

Check meters are not proactively maintained, however their output is continuously monitored by SCADA and compared to the Transpower revenue meters. Alarms are triggered where the discrepancy between the Transpower revenue meters and Wellington Electricity's check meters exceeds an acceptable tolerance.

6.5.8.2 Generators and Mobile Substations

Wellington Electricity does not own any mobile generators or substations but owns a fixed generator supporting the disaster recovery control room site. Wellington Electricity also has shared use of a generator at its corporate office however this generator is owned and maintained by others.

The works contractor provides all generation required for network operations and outage mitigation, where required.

6.5.8.3 Load Control Equipment

Fleet Overview

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 such as water heating and storage heaters at consumer premises, to control street lighting and also to provide tariff signalling on behalf of retailers using the network. All ripple injection is controlled automatically by the Foxboro master station but can also be controlled remotely from the NCR.

There are 25 ripple injection plants on the network and these are located at GXPs and zone substations. The Southern area has a 475Hz signal injected into the 33kV network with one plant per GXP and two plants injecting at the Kaiwharawhara 11kV point of supply. The Northeast and Northwest areas have a 1050Hz signal injected at 11kV at each zone substation.

The 213 previously used DC bias load control units have now all been either removed or bypassed.

An age profile of ripple plant is shown in Figure 6-75.

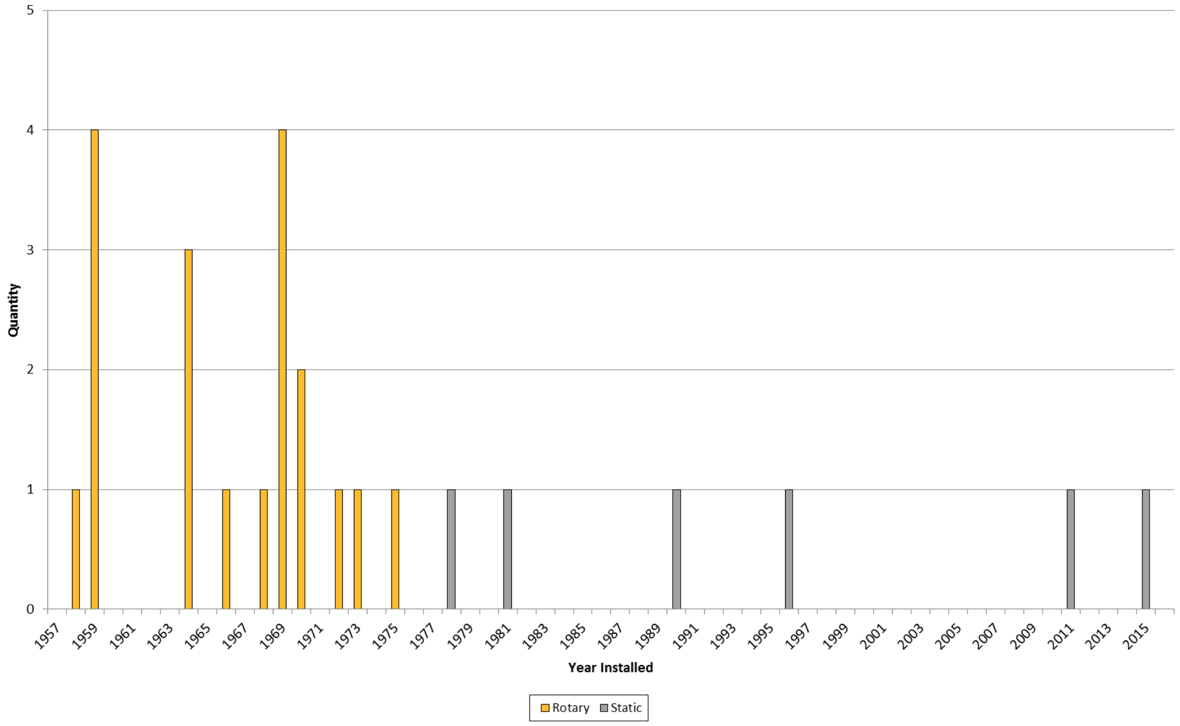


Figure 6-75 Age Profile of Ripple Plant

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 the blocking cells at GXPs, but does not own 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 6-76 Inspection and Routine Maintenance Schedule for Ripple Plant

Renewal and Refurbishment

The existing load control plant is generally reliable, with repairs and maintenance undertaken as required. Wellington Electricity has no immediate plans to replace any ripple injection plant due to age or condition but is currently reviewing its load control asset strategy which may recommend investment during the planning period.

The rotary injection plants in the Hutt Valley area, while old, are easily maintained and repaired. Interconnectivity at 11kV allows the ripple signal to be provided from adjacent substations in the event of failure.

The static injection plants in Wellington City are approaching end of life. A stock of spare parts is held locally, but many components such as integrated circuits are no longer manufactured. One of the two transmitters at Frederick Street failed during 2015. This risk had been highlighted in previous plans, and was covered by the installation of the strategic spare unit that was located on site. The old unit was unable to be repaired, and accordingly a new spare has been purchased.

There is an ongoing programme of removing bias equipment from distribution substations following the decommissioning of the DC bias load control system in 2013. Wellington Electricity is working with metering equipment owners to ensure that load control can be preserved at those sites.

Potential replacements for the Foxboro master station are currently being evaluated. This upgrade will require the replacement of the load control PLCs located at injection plants.

Strategic Spares

The spares held for load control plant is shown in Figure 6-77.

Strategic Spares	
Injection plant	A spare 24kVA rotary motor-generator set is held for the 11kV ripple system in the Hutt Valley. A spare 300kVA solid state transmitter is held at Frederick Street to cover a failure at any of the four Wellington city locations. An assortment of coupling cell equipment is held in store.
Controllers	A spare Load Control PLC is kept as a strategic spare, as the same type is used across the network.

Figure 6-77 Spares Held for Load Control Plant

Expenditure Summary for Other Network Assets

Figure 6-78 details the expected expenditure other network assets by regulatory year.

Expenditure Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Load Control PLC Replacement	1,300	0	0	0	0	0	0	0	0	0
Reactive Capital Expenditure	400	400	400	400	400	400	400	400	400	400
Capital Expenditure Total	**1,700**	**400**	**400**	**400**	**400**	**400**	**400**	**400**	**400**	**400**
Preventative Maintenance	125	125	70	70	68	68	68	68	68	68
Corrective Maintenance	88	150	153	185	136	216	223	250	283	280
Operational Expenditure Total	**213**	**275**	**223**	**255**	**204**	**284**	**291**	**318**	**351**	**348**

Figure 6-78 Expenditure on Other Network Assets
($K in constant prices)

6.5.9 Assets Located at Bulk Electricity Supply Points Owned by Others

Wellington Electricity owns a range of equipment installed at Transpower GXPs. These assets are included in the asset categories listed above, but are described further below.

6.5.9.1 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 underground cabled, whereas in the Hutt Valley and Porirua areas many circuits are connected to the GXP via an overhead line.

6.5.9.2 11kV switchgear

Wellington Electricity owns the 11kV switchgear located within the Kaiwharawhara GXP. The 11kV switchboards at all other GXPs where supply is given at 11kV are owned by Transpower.

6.5.9.3 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.

6.5.9.4 SCADA, RTUs and Communications Equipment

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

6.5.9.5 DC Power Supplies and Battery Banks

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

6.5.9.6 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 the Takapu Road, Melling and Upper Hutt GXPs.

6.6 Building Resilience Expenditure

6.6.1 Substation Building Seismic Strengthening Programme

As discussed in Section 5, specialist consultants assessed 47 buildings as being confirmed or suspected to be earthquake prone, out of 328 buildings assessed. The initial 17 had DSAs completed and strengthening costs estimated.

Three substation buildings (176 Wakefield Street, Riddiford Street, and Moana Road) were strengthened in 2015 at a total cost of approximately $250,000.

The remaining 14 confirmed sites that require seismic upgrades during the planning period are shown in Figure 6- 79:

Substation	Building Type	Year Assessed	NBS Result	Budgetary Estimate to Strengthen
Gracefield	Zone Substation	2013	30%	230
Chaytor St	Distribution Sub	2012	<20%	135
Evans Bay	Zone Substation	2013	33%	150
Ghuznee St	Distribution Sub	2013	24%	200
21 Tory St	Distribution Sub	2013	8%	350
Boulcott St	Distribution Sub	2014	12%	165
449 Jackson St	Distribution Sub	2013	26%	75
204 Naenae Rd	Distribution Sub	2013	23%	100
Naenae	Zone Substation	2013	20%	375
Rutherford St	Distribution Sub	2013	22%	100
Hartham Towers	Distribution Sub	2013	30%	50
Porirua Bridge	Distribution Sub	2014	30%	60
9 Duncan Terrace	DC Station	2012	25%	175
Newtown	Distribution Sub	2011	14%	1,000
Total				**2,800**

Figure 6-79 Confirmed Earthquake-prone Sites Requiring Seismic Upgrade ($K in constant prices)

The 30 sites shown in Figure 6-80 were identified as likely earthquake prone during the IEP assessments conducted in 2015 subsequent to the submission of the last AMP. These sites still need to have DSAs carried out.

Substation	Building Type	Year Assessed	NBS Result	Budgetary Estimate to Strengthen
Wakefield B	Distribution Sub	2015	10%	90 - 115
52 Ira St	Distribution Sub	2015	10%	160 - 200
66 Salamanca Rd	Distribution Sub	2015	25%	190 - 230
Roseneath	Distribution Sub	2015	30%	180 - 210
62 Hataitai Rd	Distribution Sub	2015	30%	110 - 145
Kano St	Distribution Sub	2015	20%	105 - 130
Harriett St	Distribution Sub	2015	25%	75 - 100
Kowhai Rd	Distribution Sub	2015	15%	190 - 230
20 Lennel Rd	Distribution Sub	2015	25%	145 - 155
Tinakori Rd	Distribution Sub	2015	15%	110 - 130
Dascent St	Distribution Sub	2015	15%	150 - 175
6 Messines Rd	Distribution Sub	2015	20%	140 - 165
13 Allington Rd	Distribution Sub	2015	30%	50 - 75
59 Upland Rd	Distribution Sub	2015	20%	125 - 165
Maida Vale Rd	Distribution Sub	2015	30%	95 - 115
Warwick St	Distribution Sub	2015	25%	120 - 140
Grant Rd	Distribution Sub	2015	20%	90 - 110
San Sebastian Rd	Distribution Sub	2015	25%	115 - 140
Rimu Rd	Distribution Sub	2015	25%	170 - 200
Trelissick Crescent	Distribution Sub	2015	15%	75 - 105
Cornford St	Distribution Sub	2015	25%	85 - 110
Standen St	Distribution Sub	2015	15%	85 - 110
30 Owen St	Distribution Sub	2015	20%	85 - 110
The Parade	Distribution Sub	2015	25%	100 - 130
Fort Opau	Distribution Sub	2015	25%	95 - 115
Vogel St	Distribution Sub	2015	20%	70 - 95
36 Bay St	Distribution Sub	2015	20%	95 - 120
Trafalgar St Kiosk	Distribution Sub	2015	20%	85 - 110
Queen Margarets	Distribution Sub	2015	25%	100 - 140
Porirua Hospital	Distribution Sub	2015	30%	125 - 150
Total				**3,410 – 4,225**

Figure 6-80 Suspected Earthquake-prone Sites ($K in constant prices)

6.7 Asset Replacement and Renewal Summary for 2016-2026

The total projected capital budget for asset replacement and renewal for 2016 to 2026 is presented in Figure 6-81. This includes provision for replacements that arise from condition assessment programmes during the year. For the later years in the planning horizon, these projections are less certain in nature. Whether they proceed will depend on the risks to the network and the risks relative to other asset replacement projects. Should the consequence of failure increase, or 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.

Asset Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission	300	300	300	300	300	300	300	1,175	2,925	300
Zone Substations	930	2,070	1,815	1,260	1,480	250	250	250	250	250
Distribution Poles and Lines	8,485	7,250	6,495	6,182	5,883	7,150	7,300	8,400	7,900	7,900
Distribution Cables	1,115	1,255	1,294	1,190	1,644	2,136	2,830	3,626	3,724	4,523
Distribution Substations	3,375	2,375	2,500	2,500	2,625	3,000	3,500	3,500	3,500	3,500
Distribution Switchgear	4,617	4,465	3,890	3,525	3,150	3,123	3,650	4,150	4,150	4,150
Other Network Assets	3,913	2,333	3,088	3,034	2,506	2,075	1,900	1,900	1,900	1,900
Total	**22,735**	**20,048**	**19,382**	**17,991**	**17,705**	**20,084**	**21,530**	**23,501**	**25,849**	**23,823**

Figure 6-81 System Asset Replacement and Renewal Capital Expenditure Forecast ($K in constant prices)

A breakdown of forecast preventative maintenance expenditure by asset category is shown in Figure 6-82. This budget is relatively constant, and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

Asset Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission	116	116	116	116	116	116	116	116	114	114
Zone Substations	304	302	293	272	261	271	266	271	261	271
Distribution Poles and Lines	444	441	439	437	434	433	431	429	428	427
Distribution Cables	0	0	0	0	0	0	0	0	0	0
Distribution Substations	435	435	435	435	435	435	435	435	435	435
Distribution Switchgear	729	728	728	727	727	727	727	727	727	727
Other Network Assets	275	275	220	220	218	218	218	218	218	218
Total	**2,303**	**2,297**	**2,231**	**2,207**	**2,191**	**2,200**	**2,193**	**2,196**	**2,183**	**2,192**

Figure 6-82 Preventative Maintenance by Asset Category ($K in constant prices)

The forecast corrective maintenance expenditure by asset category is shown in Figure 6-83. This excludes capitalised maintenance, which is instead incorporated into the capital expenditure forecast in Figure 6-81. These forecasts are based on historical trends and forecast asset replacements, however year on year variances across the different asset categories will occur depending on the nature of the corrective maintenance that is required in any given year.

Asset Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission	0	0	0	0	0	0	0	0	0	0
Zone Substations	164	163	163	165	166	168	170	173	174	177
Distribution Poles and Lines	913	832	824	763	764	858	866	874	880	880
Distribution Cables	163	169	175	181	187	194	200	207	215	222
Distribution Substations	960	872	938	940	937	980	977	974	971	968
Distribution Switchgear	740	734	727	722	715	709	703	698	692	686
Other Network Assets	143	205	208	240	191	271	278	305	338	335
Total	**3,083**	**2,975**	**3,035**	**3,011**	**2,960**	**3,180**	**3,194**	**3,231**	**3,270**	**3,268**

Figure 6-83 Corrective Maintenance by Asset Category ($K in constant prices)

6.7.1 Reliability, Safety and Environmental Programmes for 2016-2026

Asset management expenditure that is not directly the result of asset health drivers is categorised into quality of supply and other reliability, safety and environmental expenditure. Quality of supply projects target the worst performing feeders. Other reliability, safety and environmental projects includes the seismic programme. The total projected capital budget for these categories is presented in Figure 6-84.

Programme	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Worst Performing Feeders	1,631	1,232	1,300	863	1,030	900	919	963	969	1,100
Total Quality of Supply	**1,631**	**1,232**	**1,300**	**863**	**1,030**	**900**	**919**	**963**	**969**	**1,100**
Seismic Programme	944	1,010	988	1,016	1,193	1,288	1,336	TBD	TBD	TBD
33kV Temporary Line Corridor Components	300	300	150	0	TBD	TBD	TBD	TBD	TBD	TBD
Total Other Reliability, Safety and Environment	**1,244**	**1,310**	**1,138**	**1,016**	**1,193**	**1,288**	**1,336**	**0**	**0**	**0**

Note: TBD figures to be determined following 2016 resiliency project study.

Figure 6-84 Reliability, Safety and Environmental Capital Expenditure ($K in constant prices)

6.7.2 Asset Management Expenditure

The total capital and operational expenditure forecasts are shown in Figures 6-85 and 6-86. For clarity, the operational expenditure forecast does not include non-maintenance related operational expenditure. Service interruptions and emergency maintenance 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 down into asset category detail levels.

Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Asset Replacement & Renewal	22,735	20,048	19,382	17,991	17,705	20,084	21,530	23,501	25,849	23,823
Reliability, Safety & Environment (other)	1,244	1,310	1,138	1,016	1,193	1,288	1,336	0	0	0
Quality of Supply	1,631	1,232	1,300	863	1,030	900	919	963	969	1,100
Subtotal - Capital Expenditure on Asset Replacement Safety and Quality	**25,610**	**22,590**	**21,820**	**19,870**	**19,928**	**22,272**	**23,785**	**24,464**	**26,818**	**24,923**

Figure 6-85 Asset Management Capital Expenditure Forecast ($K in constant prices)

Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Service interruptions & emergencies maintenance	4,151	4,139	4,127	4,115	4,103	4,091	4,079	4,067	4,055	4,043
Vegetation management	1,425	1,432	1,439	1,446	1,453	1,460	1,467	1,474	1,481	1,488
Routine & corrective maintenance and inspection maintenance	7,464	7,375	7,424	7,457	7,500	7,558	7,630	7,721	7,834	8,074
Asset replacement & renewal maintenance	1,157	1,173	1,158	1,173	1,195	1,216	1,240	1,263	1,282	1,293
Subtotal - Operational Expenditure on Asset Management	**14,197**	**14,119**	**14,148**	**14,191**	**14,251**	**14,325**	**14,416**	**14,525**	**14,652**	**14,898**

Figure 6-86 Asset Management Operational Expenditure Forecast ($K in constant prices)

Section 7:
Network Development

7 Network Development

This section sets out Wellington Electricity's network development investment plan over the next 10 years. The purpose of network development is to safely deliver the level of capacity and security of supply required to achieve, over the planning period, the service levels and network performance described in Section 4.

Due to the uncertainty in how demand for network capacity will change over time, planning for development investment requires constant monitoring of the need for projects and the investment timing to ensure it is efficient and that consumers are receiving the price and quality outcomes they are expecting.

This section covers:

- Network planning policies and standards;
- Demand forecast;
- An overview of the development plans;
- The network development plans for the Southern, Northwestern and the Northeastern Areas; and
- Customer initiated projects and relocations.

7.1 Network Planning Policies and Standards

Wellington Electricity establishes its network planning policies and standards through engagement with retailers, consumers and other stakeholders. The purpose of these policies and standards is to ensure the network delivers the service levels discussed in Section 4.

The policy and standards cover the following areas:

- Security criteria – which specify the network capacity (including levels of redundancy) required to ensure the level of reliability is maintained;
- Technical standards – voltage levels, power factor and harmonic level standards to ensure the network remains safe and secure, and that overall network costs are minimised;
- Standardised designs- these reduce design costs and minimise spare equipment holding costs, leading to lower overall project and maintenance costs;
- Emerging network technology and the impact that it may have on investment and operations;
- The impact of embedded generation on planning;
- The use of non-network solutions within the planning process;
- The definition of asset capacity utilised for planning purposes; and
- Demand forecasting policies and methodology.

Each of these is discussed in the sections below.

7.1.1 Security Criteria

The design of Wellington Electricity's network is based on the security criteria shown in Figure 7-1 (subtransmission criteria) and Figure 7-2 (distribution criteria).

The security criteria are consistent with industry best practice[23] and are designed to:

- Match the security of supply with consumer requirements;
- Optimise capital and operational expenditure without a significant increase in supply risks; and
- Increase asset utilisation.

The security criteria accept there is a small risk that supply may be interrupted when a fault occurs during peak demand times.

The Wellington Electricity subtransmission network consists of a series of radial circuits from Transpower's GXPs to the zone substations. The zone substations do not have a 33kV bus and the subtransmission circuits connect directly onto the high voltage terminals of the 33/11kV power transformers. In the Southern Area the 11kV bus is normally operated open to restrict fault levels. Within the Northwestern and Northeastern areas the 11kV bus is operated closed. The network utilises equipment cyclic capacity to meet sustained peak demand and provide N-1 security. At the zone substations where the 11kV bus is normally operated open, the brief interruption to consumers following a subtransmission or transformer fault, while the bus tie is closed, is considered to satisfy the N-1 security criteria.

<u>Subtransmission</u>

The length of time (defined as a percentage) when the subtransmission network cannot meet N-1 security is defined for each category of consumer. Absolute limits are also set on the maximum load that would be lost for the occurrence of a contingent event. The security criteria is based on the sustained peak demand which is calculated as 'loading that lasts for two hours and occurs at least five times during the year'. This differs from the anytime peak demand which is measured over a 30 minute period and can occur as a result of abnormal system operations.

Figure 7-1 shows the applicable security criteria for the subtransmission network.

[23] *Guide for Security of Supply*, Electricity Engineers' Association, August 2013.

Type of Load	Security Criteria
CBD	N-1 capacity[24], 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 capacity 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 capacity for 95% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.

Figure 7-1 Security Criteria for the Subtransmission Network

Distribution

Figure 7-2 shows the applicable security criteria for the distribution network.

Type of Load	Security Criteria[25]
CBD or high density industrial	N-1 capacity 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 capacity 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 capacity 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 7-2 Security Criteria for the Distribution Network

Basis for the criteria

While the reliability of Wellington Electricity's distribution system is high, notwithstanding the difficult physical environment in which the system must operate[26], it is uneconomic to design a network where supply interruptions will never occur. 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 electricity demand on the network varies according to the

[24] A brief supply interruption of up to five minutes may occur following an equipment failure while the network is reconfigured.

[25] 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.

[26] 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.

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.

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

The security 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. Wellington Electricity has emergency plans in place to prioritise response and repair efforts to assist mitigating the impact of such situations (as discussed in Section 5) but, when they occur, longer supply interruptions than shown in the tables are possible.

Most of the 11kV feeders in the Wellington CBD, in some locations around Wellington's eastern suburbs, and in 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 urban 11kV network outside these areas typically comprises radial feeders with a number of mid-feeder switchboards with circuit breakers. The radial feeders are connected through 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 flexibility, distribution feeders are not operated at their full thermal rating under normal system operating conditions. The maximum feeder utilisation factor at which Wellington Electricity currently operates the distribution feeders during normal and contingency operation is identified in the table in Figure 7-3. This is a guideline limit and signals the point where greater analysis is required. The actual N-1 post event loading and implementation of any required solutions is determined using contingency analysis.

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 7-3 11kV Feeder Utilisation during Normal and Contingency Operation

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

7.1.2 Voltage Levels

Subtransmission voltage is nominally 33kV in line with the source voltage at the supplying GXP. The voltage used at the 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 consumers, supply can also be connected at 11kV or 33kV depending upon the 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 fluctuations. Supplies at other voltages must be kept within +/-5% of the nominal supply voltage except for momentary fluctuations, unless agreed otherwise with consumers.

Design of the network takes into account voltage variability due to changes in loading and embedded generation under normal and contingency conditions. All Wellington Electricity zone substation 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 at different network locations.

7.1.3 Fault Levels

Wellington Electricity operates its 11kV network to restrict the maximum fault level to 13kA which ensures the fault rating for several legacy makes and models of switchgear is not exceeded. Restriction of fault levels is achieved by operating all zone substations supplied from Central Park and Wilton GXPs with a split 11kV bus such that each zone substation transformer is supplying an independent bus section. The prospective fault level at all other zone substations does not exceed 13kA, meaning the 11kV bus can be operated closed, with the supply transformers supplying a common bus. New switchgear is typically rated for 25kA for use within zone substations and 21kA for use within the distribution network.

7.1.4 Power Factor

All connected customers are responsible for ensuring that their demand for reactive power does not exceed the maximum level allowed, or the power factor limits specified in Wellington Electricity's Distribution Code Section 3.3.3.2. The power factor of a customer's load measured at the metering point must not be less than 0.95 lagging at all times. Corrective action may be requested by Wellington Electricity if the customer's power factor falls below this threshold at any time. All demand forecasting and network planning assumes the power factor of all loads is 0.95 lagging.

7.1.5 Acceptable Harmonic Distortion

Harmonic currents result from the normal operation of nonlinear devices on the power system. Voltage distortion results as these currents cause nonlinear voltage drops across the system impedance. Harmonic distortion levels are characterised by the complete harmonic spectrum with magnitudes and phase angle of each individual harmonic component. It is also common to use a single quantity, the "Total Harmonic Distortion" (THD), as a measure of the magnitude of harmonic distortion. Current and voltage harmonic levels are to be within the 5% THD limit specified in the Electrical Safety Regulations 2010 at the point of supply to the customer.

7.1.6 Standardised Designs

The implementation of standardised designs for common developments allows for improvements in safety by design principles, significant reduction in design expenditure and reduces the requirement for review and assessment. Standardised designs also aid in consistency in installation, commissioning and maintenance processes, thus improving familiarity for field staff and potentially reducing the cost of implementation.

Standardised designs are implemented for the purpose of asset and installation specification. At present, design standards are utilised for protection design, zone substation and distribution level earthing and LV reticulation.

Due to the quantity of residential sub-divisions completed, or planned, in recent years, an underground subdivision design standard has been developed.

There is no standardisation of high voltage (HV) network augmentation because these are project by project dependent.

7.1.7 Energy Efficiency

The processes and strategies used by Wellington Electricity that promote the energy efficiency of the network are:

- Network planning – to design systems that do not lead to high losses or inefficient conveyance of electricity by selecting the correct conductor types and operating voltages in order to minimise total costs (including the cost of losses) over the lifetime of the asset;

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

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

7.1.8 Non-Network Solution Policy

Non-network solutions include load control, demand side management solutions, use of emerging technologies and network reconfigurations.

Wellington Electricity's load control system is used to reduce peak demand on the network by moving load to off-peak periods to optimise investment in network capacity. This has the effect of deferring demand-driven network investments. The use of the load control system has resulted in the significant deferral of investment and has provided an effective means of promptly returning supply to consumers following network outages.

Wellington Electricity specifies equipment for use that incorporates new technologies where it is practicable and economic. This means that new technologies will be implemented if the benefits to the network and stakeholders meet or exceed the additional costs incurred in installing and using them. Therefore, it is unlikely that wide scale replacements of existing assets will occur; rather new equipment 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.

Because of the uncertainty and fast changing nature of the emerging technologies, Wellington Electricity's approach is:

- To track trends on the uptake of new technology;

- Incorporate forecast uptake rates in our load and energy forecasts;
- Provide tariff structures to provide incentives to avoid network peaks;
- Utilise new technology (for example EVs, new network technology); and
- Include emerging technology options in business case options at project approval.

To date the cost of implementing emerging technologies have been found to be significantly higher than the alternative network-based solutions. As discussed in Section 3, Wellington Electricity is introducing a new tariff structure to incentivise consumers to use new technologies in a way that smooths peak demand.

7.1.9 Impact of Distributed Generation

The magnitude of small distributed generation currently installed within the network is relatively low[27] compared to other areas in NZ and is expected to remain relatively low across the planning period. This assumption will be monitored and re-assessed in the event of large scale uptake of distributed generation in the future and annually in the AMP process. Wellington Electricity welcomes enquiries from third parties interested in installing embedded generation and has a well-defined connection policy, as described below.

7.1.9.1 Connection policy

Wellington Electricity has a distributed generation connection policy and procedures for the assessment and connection of distributed generation in line with the Electricity Industry Participation Code 2010, Part 6.

Example of distributed 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 extent the proposal meets the following requirements will be considered in developing a technical and commercial solution with stakeholders:

- The expected level of generation at peak demand times (availability of the service at peak demand times determines the extent that it will off-set network investment);

[27] Installed capacity, excluding standby generation and Mill Creek (connected at 33kV), is only 11.4MVA, or 0.2% of the system demand.

- 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; and
- Commercial arrangements must be consistent with avoided cost principles.

If the above issues can be managed, and the dispatch of generation can be co-ordinated with system peaks or constraints, then the use of distributed generation as part of a demand side management programme benefits Wellington Electricity and its consumers.

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

7.1.10 Asset Capacity Definition

Asset capacity is defined as follows:

- Transformers – The transformer nameplate ratings provide the continuous asset capacity (based on a continuous uniform load profile), the cyclic capacity (based on the presence of fan forced cooling and oil circulation pumps) and a short duration (2 hour) emergency overload rating (dependent on the maximum operating temperature of the transformer). For operational and planning purposes, the cyclic capacities are used;
- Subtransmission Cables/Lines – Thermal conductor capacity is determined through CYMCAP modelling, considering the effect of soil resistivity, the prospective load profile and resulting thermal inertia, mutual heating due to adjacent conductors and configuration of installation. Soil and ambient temperature variations between seasons are also allowed for, providing a set of normal, cyclic and emergency ratings. For operational and planning purposes, the cyclic ratings are used;
- Subtransmission Circuit Capacity – This is determined based on the lowest rated component of the subtransmission circuit, i.e. a transformer may be rated to 36MVA cyclic while the supplying subtransmission cable is only capable of 21MVA cyclic and 17MVA cyclic during winter and summer respectively. Thus the effective rating of the subtransmission circuit is limited to the seasonal cyclic rating of the subtransmission cable; and
- Distribution Cables/Lines – Distribution feeders are rated based on the continuous capacity (provided by manufacturers datasheets) of the cable/line. Distribution cable capacity is the capacity of the lowest rated segment of the cable, thus a constraint may not be apparent at the feeder supply point, but an undersized section of cable on a particular feeder may constrain capacity at a certain point along the feeder.

The capacity of all network elements is modelled in the DigSILENT PowerFactory network model, providing ready analysis of network integrity against the security standard.

7.2 Demand Forecast 2016 to 2026

Growth in peak demand drives system constraints and the need for additional investment, either in the network or an alternative means of providing or managing the capacity. This section describes Wellington

Electricity's methodology and assumptions utilised to determine the sustained peak demand forecast for the network.

Despite the overall decline in energy use, the sustained peak demand is forecast to grow in some localised areas of the network, driven by new commercial and residential developments. This reflects a decoupling between the overall volume of energy consumed and the peak demand. There is also a strong correlation between peak demand and climatic conditions. Generally, demand peaks within the Wellington Region are driven by winter temperatures on the coldest days.

While the overall Wellington Electricity load is traditionally winter peaking, recent trends have shown that a few of the Zone Substations within the Wellington CBD are now trending towards a summer peak.

7.2.1 Demand Forecast Methodology

The forecasting methodology utilised by Wellington Electricity is based on a building block approach, from 11kV feeder level up, utilising historical trends in sustained peak demand. The methodology consists of five components:

1. A starting demand level is based on the sustained peak demand from the year ending 31 December 2015;
2. The average growth rate over the last 10 years is utilised to establish the underlying forecast growth rate;
3. The band of uncertainty in the forecast is based on two components:
    a. for the first five years of the forecast, in addition to the average, high and low growth rates are applied based on the observed high and low variance from the average sustained peak demand, over the last five years. These are known as the growth scenarios. These three growth scenarios are extrapolated over the 5-10 year horizon by using the average growth rate to provide a medium-long term forecast with a band of uncertainty; and
    b. over the whole forecast period a mild, average and cold variance based on the observed spread in peak demand against winter temperature plus one case for summer temperatures. These are known as the four temperature variations applied to the forecast;
4. The addition of known future step change demand at specific sites; and
5. An adjustment for EV and PV impact on consumption over the long term.

The output of the forecasting is a peak demand spread over 12[28] forecast data points per year corresponding to combinations of the demand growth and temperature variations, all centred around the long term average growth rates.

These forecast scenarios are determined at the feeder level, and are aggregated from "bottom up" to provide the Zone substation, GXP, region and system wide forecasts allowing for diversity at each level. An overview of the demand forecast methodology is shown in Figure 7-4.

[28] Twelve scenarios from permutations of the three growth scenarios (high, historical, low) and the four seasonal temperature variations (Summer, Mild Winter, Average Winter and Heavy Winter)

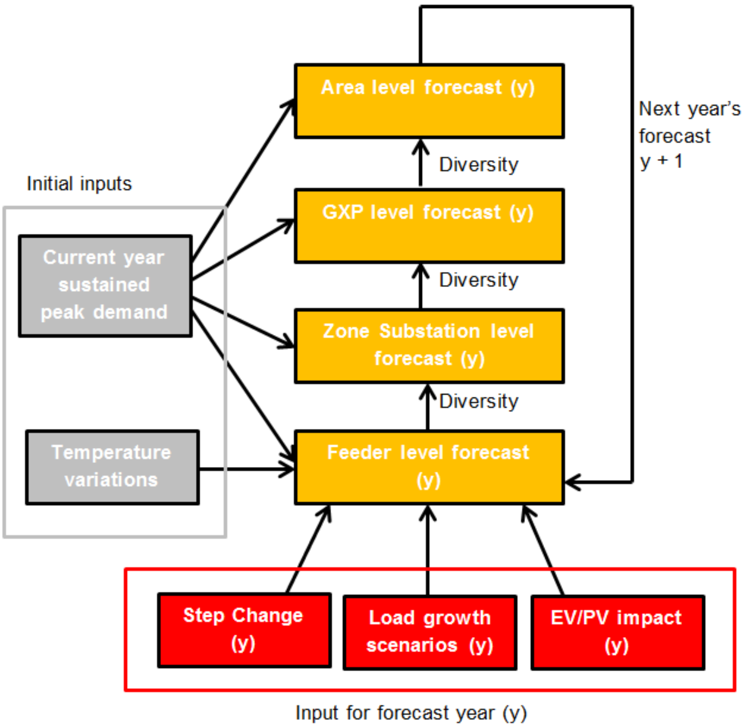


Figure 7-4 Demand Forecasting Methodology

This model is used to determine when subtransmission and feeder level constraints are likely to occur and provides an annual maximum demand that can be used in load flow modelling.

At the subtransmission level, the 60th percentile between the upper and lower range of the sustained peak demand forecast values (differentiated by season) is used for planning purposes and has been termed, the Likely Peak Demand (LPD).

The 60th percentile allows for a sufficient margin of error given the load at risk and the scale of augmentation investment typically required when a constraint is identified at the subtransmission level. This is plotted against the applicable N-1 subtransmission capacity constraints to determine the subtransmission security of supply.

7.2.1.1 Forecasting Assumptions and Inputs

The sustained peak demand forecast for the current planning period is based on the following assumptions:

- The use of load control is assumed to remain constant as per current practice;
- No allowance is made for any significant demand changes due to a major weather events or unforeseen network condition causing significant outages or abnormal operation of the network; and
- No significant impact is assumed from disruptive technologies such as PV or distributed generation, as discussed in Section 7.2.5.

The sustained peak demand forecast is based on the following information:

- Half-hourly demand data per zone substation feeder is captured by the SCADA system. The demand at each GXP is metered through the time-of-use revenue metering;

- Temperature volatility is based on historical temperature data recorded at three NIWA measurement sites based within the three areas of the Wellington network, the Southern, Northwest and Northeast coverage areas;
- Highly likely or confirmed step change loads, based on consumer connection requests are included in the forecast;
- Diversity factors[29] that provide peak coincident demand are calculated from historical recorded data;
- Typical demand profiles based on the majority load type in the zone; and
- Population forecasts from NZ Statistics[30] are used as a benchmark for comparison with the long term demand forecast.

These assumptions, data sets and trend analysis are reviewed each year and the expected impacts of any changes are incorporated into the forecast.

7.2.2 Temperature Variation

The variation in average temperature over the year is used to create forecast scenarios. Historically there is a strong inverse correlation between the temperature during the winter months and the recorded maximum demand. A year with a colder/stormier winter typically results in higher winter peak loading and consequently a higher maximum demand, while a year with a milder winter will experience lower maximum demand. There is no current identified correlation between summer temperature variations and the summer loading on the network. As such, the demand model assumes that summer temperature variations have no effect on the annual peak load profile.

To model the dependency on the winter temperatures, three scenarios were developed for each of the three network areas based on smoothed historical temperature variations provided from monitoring stations within the respective area. These load scenarios are shown as red lines in Figure 7-5, and cover mild, average and cold winter temperature profiles. Because of the known relationship between temperature and maximum demand, these temperature profiles are used to calculate the three load scenarios. Figure 7-5 shows how the winter temperature volatility correlates the volatility in maximum demand.

[29] Diversity factors represent the difference in times of peak demand between different sites
[30] NZ Statistics Subnational Population Projections: 2006 (base) – 2031 (October 2012 update). Used for 10+ year forecasting.

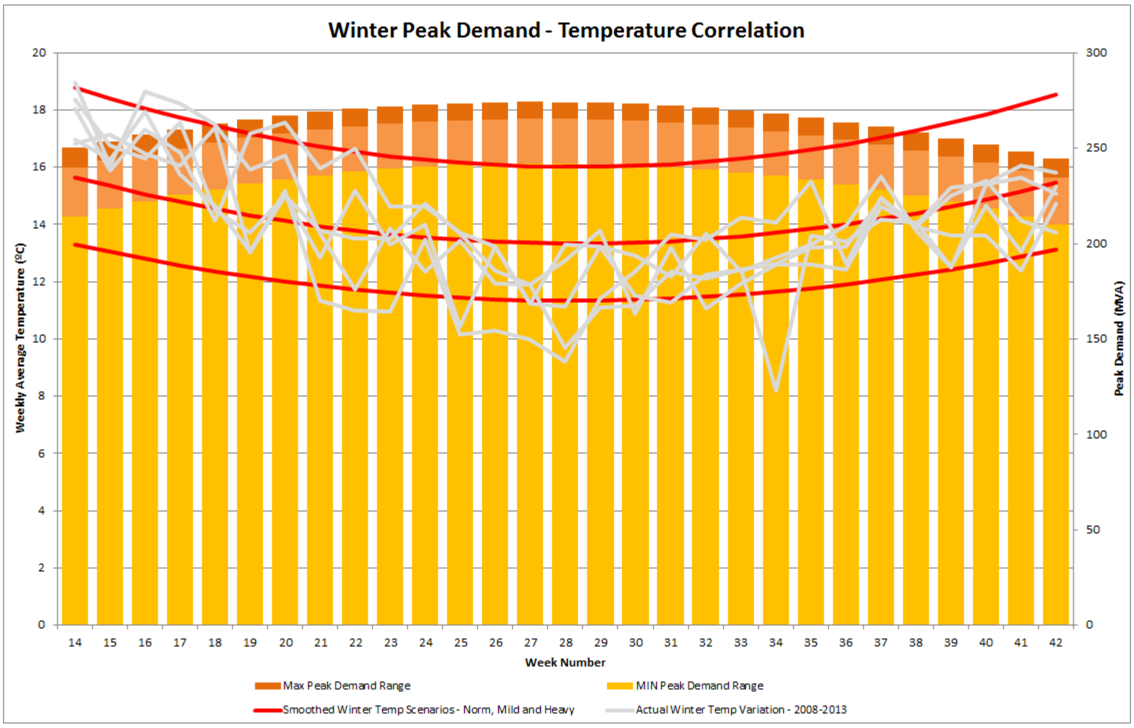


Figure 7-5 Temperature Volatility Correlation to Peak Demand Range

For example, for week 31, there is a high degree of certainty that the temperature for the network area shown will be within the range from 12° C to 15°C. Using the developed correlation between temperature and maximum demand volatility, maximum demand for the network area for week 31 will be between 240MVA and 275MVA.

7.2.3 Step Change Loads

Highly likely or confirmed step change loads are accounted for in the load forecast. These step change loads may be the result of:

- Major developments that introduce large new loads onto the network;
- New electricity generation that is expected to reduce peak demand; or
- Load reductions caused by the movement or closure of businesses.

The magnitude and location of likely step change loads is identified through customer connection requests and likely developments detailed in the individual local council District Plans. A number of property developers and businesses have flagged developments that may create new loads on the network.

The actual step change demand profile represents a material proportion of the change in network peak demand. As such, it is prudent to provide an estimation of the potential impact of large scale developments and the step change in demand expected across the region. However, the actual outcome from step change demands is always uncertain, and difficult to estimate more than 12 to 24 months in advance.

7.2.4 Typical Load Profiles

Typical annual demand profiles for the CBD and residential loads are shown in Figure 7-6 and Figure 7-7. These graphs illustrate that peak CBD loads are relatively flat throughout the year with a slight trend towards a summer peak due to air conditioning load whereas residential loads peak in winter, mostly driven by domestic heating.

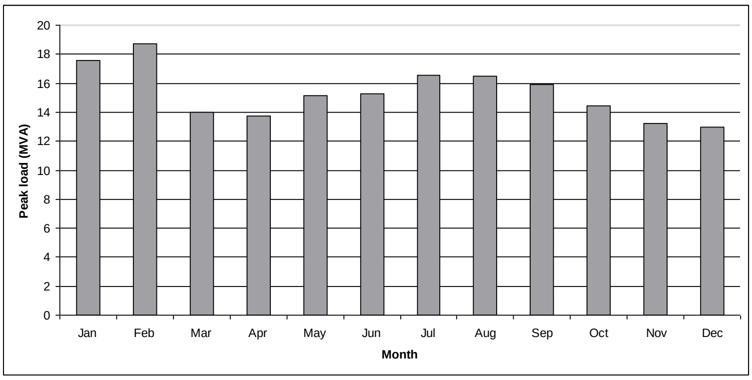


Figure 7-6 Typical CBD Monthly Peak Load Profile

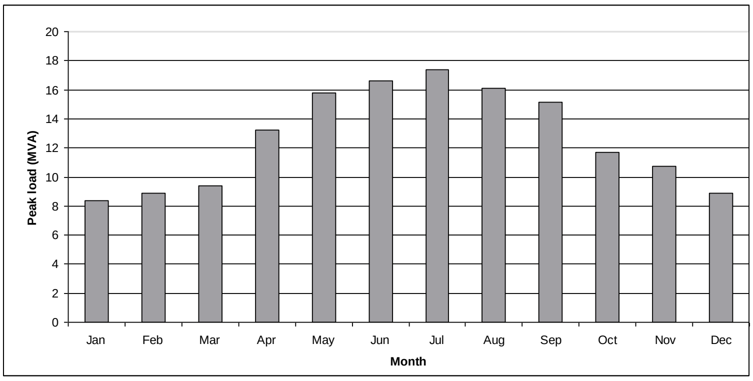


Figure 7-7 Typical Residential Monthly Peak Load Profile

Typical daily demand profiles are shown in Figure 7-8 and Figure 7-9. These graphs illustrate that the CBD daily profile peaks and then remains relatively flat through the day, whereas the residential load profile has the typical morning and early evening peaks.

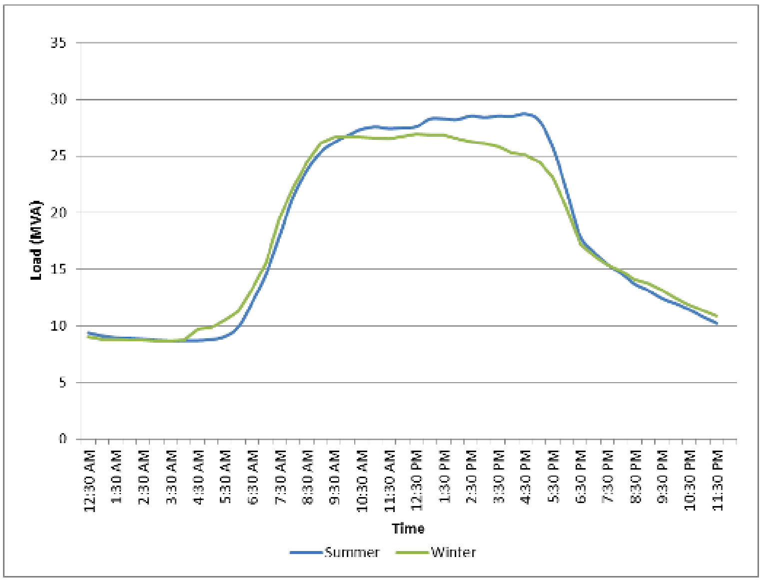


Figure 7-8 Typical CBD Zone Substation Daily Load Profile

Figure 7-9 Typical Residential Zone Substation Daily Load Profile

7.2.5 Impact of New Technology on Load Growth

The impact of new technology was considered in the demand forecast.

7.2.5.1 PV

The uptake of PV installations within the Wellington region has shown a rise over recent years. However, to date the impact on the overall demand profile has been small. Figure 7-10 shows the high level forecast in cumulative photovoltaic generation on the Wellington Electricity network. The numbers are small compared with national averages.

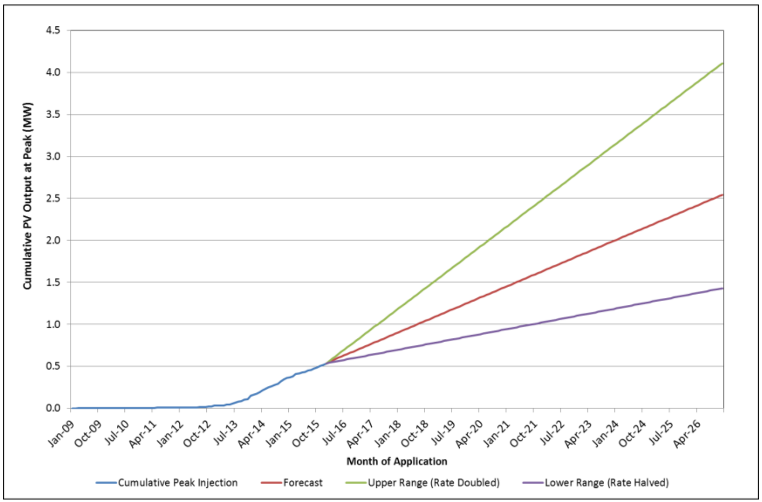


Figure 7-10 Forecasted Cumulative PV Output During Network Peak Demand

The potential impact of PV generation within the network going forward is dependent on a number of factors:

- The efficiency of the installed plant;
- The coincidence of peak PV generation to peak network demand;

- The number of sunshine hours per year;
- The forecasted rate of uptake; and
- The co-installation of batteries to move PV generation to maximum demand periods.

These factors have been built into the forecast of peak PV output during the peak network demand periods, and have been based on the following assumptions:

- During the peak demand period for the network (winter), PV output is at 5% of capacity;
- The relatively small magnitude of forecast PV output during peak network demand has negligible impact on the magnitude of network peak demand. As such, the effect of PV generation within the network is currently immaterial to the load forecasts. Larger levels of PV uptake in the future may result in the magnitude of PV output having a more significant impact to the network peak demand.

These assumptions will be revisited each year. The major impact will be the lowering of battery storage costs that could allow energy from PV generation to move to maximum demand periods.

7.2.5.2 EV sales

Availability of affordable EVs has the potential to significantly alter electricity delivery and usage patterns. It is expected that the adoption rate in New Zealand will increase over the longer term based on:

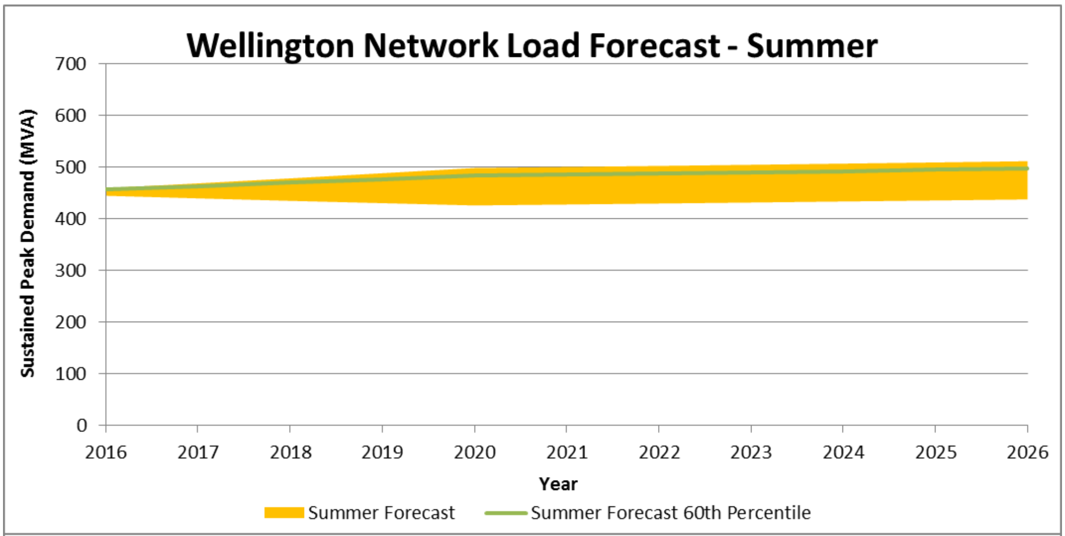
- New Zealand's high level of renewable energy generation (over 80%) is an ideal match for electric vehicles and will be seen as an appealing option for environmentally and cost conscious consumers;
- Constantly evolving energy storage systems, electric drives and charging technologies will improve efficiency and range of EVs; and
- EVs offering lower running costs than traditional internal combustion engines due to the increasing cost of fossil fuels and the higher efficiency of energy conversion from battery storage.

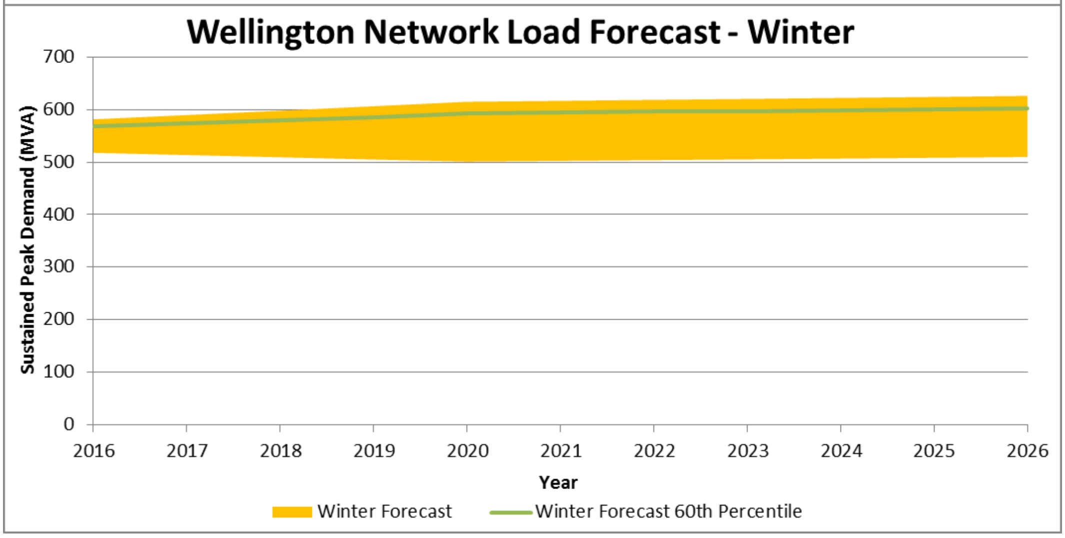
The impact of EVs on the network demand is still very small and is not accounted for in the current forecast. The expected uptake of electric vehicles in future years will be monitored and modelled.

7.2.6 Wellington Regional Peak Demand Forecast

Accounting for the forecast scenarios, including both short and long term trends, temperature variations and step change demands, the expected system maximum demand forecast to 2026 is shown in Figure 7-11. The spread shown in the yellow band indicates the variation in both forecast assumptions and temperature. The following points apply to the forecast:

- The maximum forecast value for a particular year and season indicates the worst case scenario of high growth and colder average temperatures;
- The minimum forecast value for a particular year and season indicates the mild scenario of low to negative growth and warmer average temperatures; and
- The sustained peak demand used for planning purposes is the 60th percentile of the range of sustained peak demand values resultant from the various load growth and winter temperature scenarios per year.





	Sustained Peak Demand											
	2015 Actual [31]	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System Maximum Demand (MVA)	566	565	565	565	567	569	570	572	574	575	576	577

Figure 7-11 Network Historic Demand and Forecast

In summary, sustained peak network demand is expected to grow at a rate of 0.2 – 0.4% p.a. over the next five years. This is driven by planned step change loads such as:

- Planned residential developments in the Churton Park, Aotea, Whitby, Grenada North and Upper Hutt areas; and

[31] The System Maximum Demand forecast is based on the 2015 sustained peak

- Expansion plans of a number of commercial and industrial customers.

In the long term the rate of growth in sustained peak demand is driven by a number of factors including:

- A number of buildings within the Wellington CBD that are currently undergoing re-development. High efficiency HVAC systems and better insulation and customer side demand monitoring typically result in a reduction in demand for an existing connection point;
- Uptake of new technologies such as EVs and residential PV generation and gas connections; and
- Observed diversity in peak load coincidence leading to a long term reduction of overall peak demand.

7.2.6.1 Area Sustained Peak Demand Forecasts

Figure 7-12 shows the 60th percentile of the sustained peak demand for the three areas and the aggregate demand for the Wellington region.

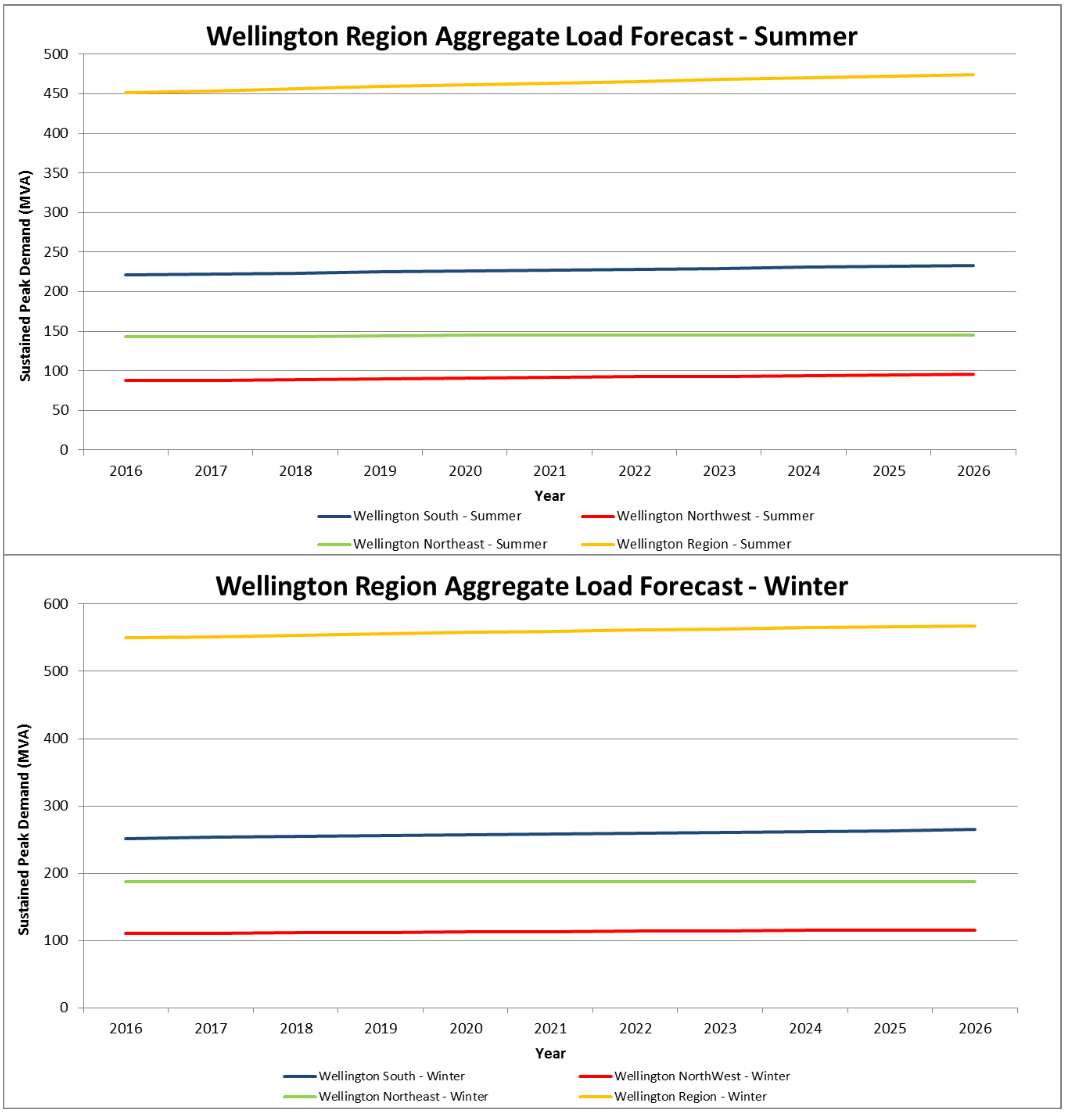


Figure 7-12 Wellington Region Aggregate Forecast

The forecasted sustained peak demand for each of the three areas of the Wellington Region shows short term peak demand growth. The Northwestern Area is forecast to experience the highest growth due to a number of residential developments expected. Overall sustained peak demand is expected to increase in the short term and level off over the long term. Overall forecast changes are relatively small and the uncertainty is high. The changes are difficult to see in Figure 7-13 but are clearer in figures 7-14 to 7-16.

7.2.7 Network Area Peak Demand Forecasts

The forecast peak demand for each network Area is described in more detail below.

7.2.7.1 Southern Area Forecast

Peak demand in the Southern Area has declined in recent years but is expected to increase due to a number of new buildings planned over the coming years. The new building developments are expected within the inner city and along the water front, around the Parliamentary Precinct and a new development at Victoria University. Figure 7-13 shows the summer and winter peak forecasts for the Southern Area.

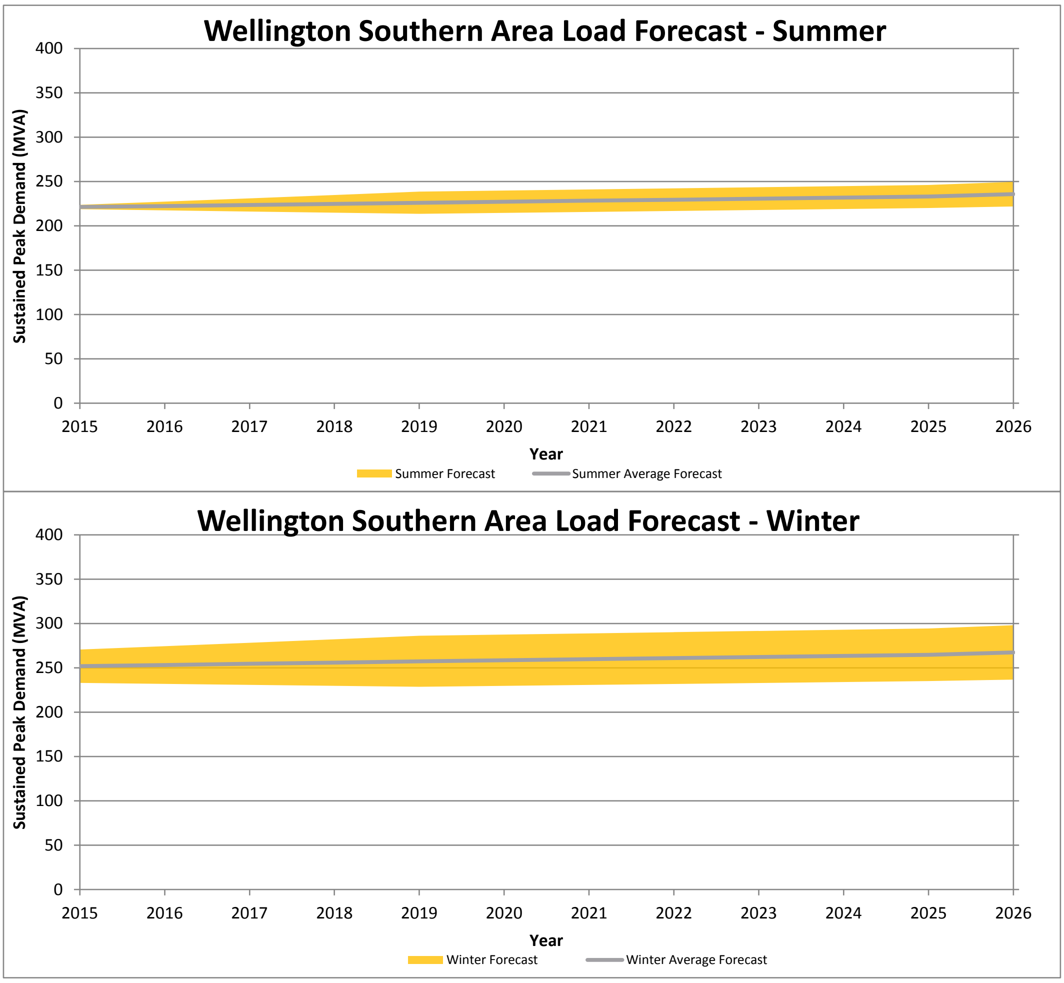


Figure 7-13 Southern Area Forecast

Energy consumption within the Southern Area network has been declining due to a general trend towards energy efficiency. This is most prevalent within the Wellington CBD, where initiatives such as high efficiency HVAC systems, better insulation and customer side demand monitoring have caused a reduction in average rate of energy consumption while not affecting the peak demand.

7.2.7.2 Step Change Developments

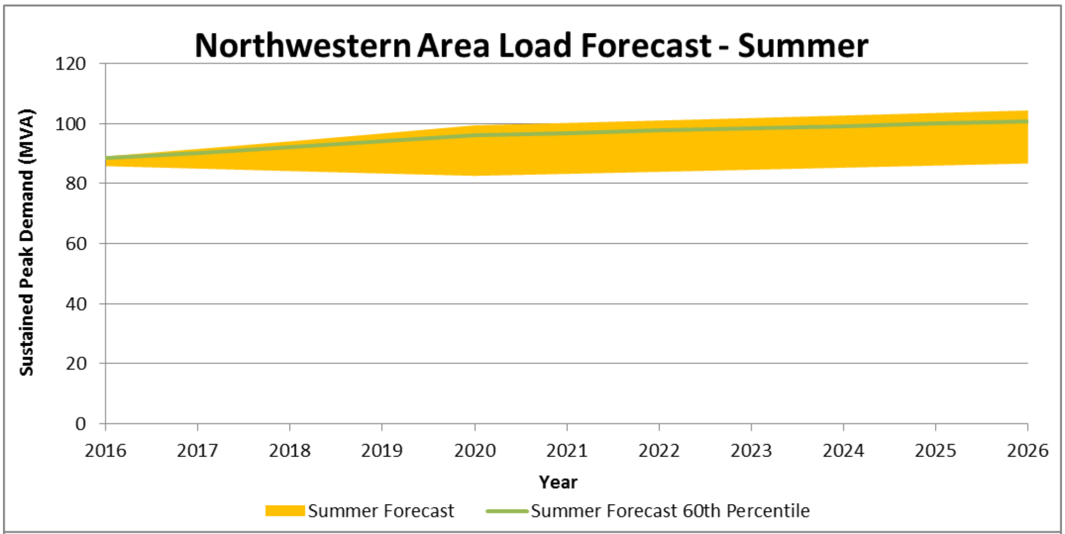
Expected developments in the Southern Area include:

- A new science building with a maximum demand of around 2MVA at the Kelburn campus of Victoria University and a redevelopment of Rutherford House in the Wellington CBD;
- Approved customer connection requests for a number of new government and ministerial buildings along Molesworth Street;
- High density residential and commercial developments in the Cuba and East Te Aro precincts, including Peter Jacksons Film Museum and Conference Centre;
- High density residential and commercial buildings along the waterfront;
- A new airport hotel at Wellington International Airport; and
- There are other tertiary institutions, hospitals and growth industries, such as businesses supporting the international film industry, which are likely to require future capacity.

While the timing of these developments is not certain, they have been included in the forecast by accounting for step change load growth on feeders supplying the relevant areas. Although not all of these will occur, other projects not currently included as step load changes will likely occur as replacements.

7.2.7.3 Northwestern Area Forecast

The Northwestern Area is continuing to grow organically with the strongest level of residential development within Wellington Electricity's network. There is relatively high interest for new residential subdivisions in the suburbs of Whitby, Grenada North and Churton Park. The Aotea subdivision, currently supplied from the Porirua and Waitangirua zone substations, is also an area of growth. Figure 7-14 shows a moderate increase in forecast summer peak and winter peak loading.



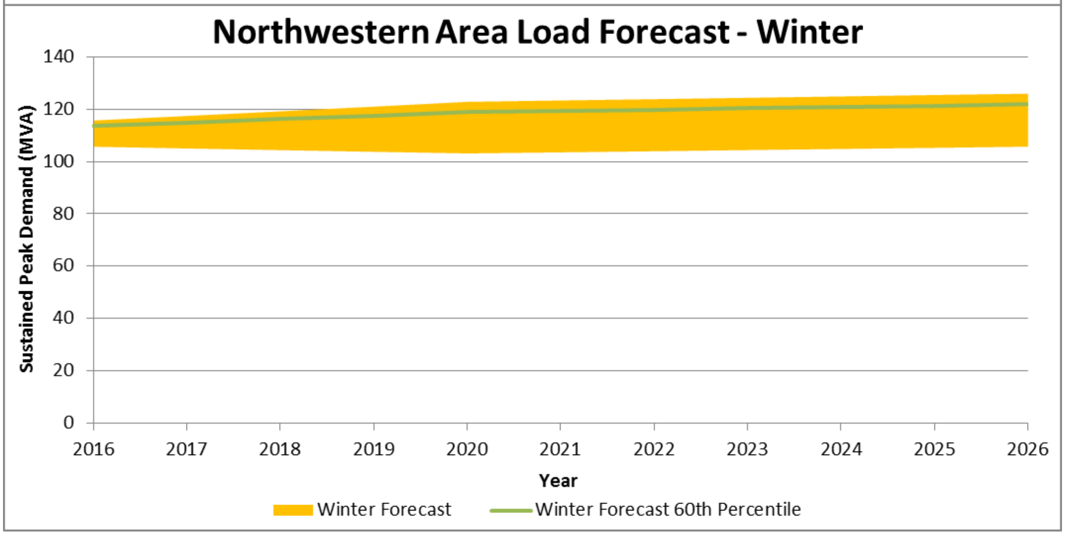


Figure 7-14 Northwestern Area Forecast

7.2.7.4 Step Change Developments

Expected developments in the Northwestern Area include:

- Residential and light commercial development at Upper and Lower Stebbings and Lincolnshire Farms;
- Medium density residential development is expected in the Johnsonville area in the latter end of the planning period, particularly around the town centre;
- Residential development at Silverwoods in Whitby is expected to contribute 700kVA peak demand within the next 10 years;
- Residential and commercial development in the Aotea Block development area is expected to contribute 3.15MVA within the next 10 years. Residential development is currently in progress at a rate of 100 lots or 150kVA of additional peak demand per year. Commercial development in the Aotea Block business park is expected to provide a further 300kVA per year in the last five years of development; and

- Planned revitalisation of the Porirua city centre is expected to proceed within the next five years. The total growth contributed over the planning period is estimated to be 2.3MVA.

While the timing of these developments is not certain, they have been included in the forecast by accounting for step change load growth on feeders supplying the relevant areas. Although not all of these will occur, other projects not currently included as step load changes will likely occur as replacements.

7.2.7.5 Northeastern Area Forecast

Peak demand in the Northeastern Area is expected to marginally increase due to localised residential and commercial developments. This is driven by planned residential sub-divisions and expansion plans of industrial customers in the Trentham and Maidstone zone substation supply areas. Figure 7-15 shows the forecast peak demand over the planning period.

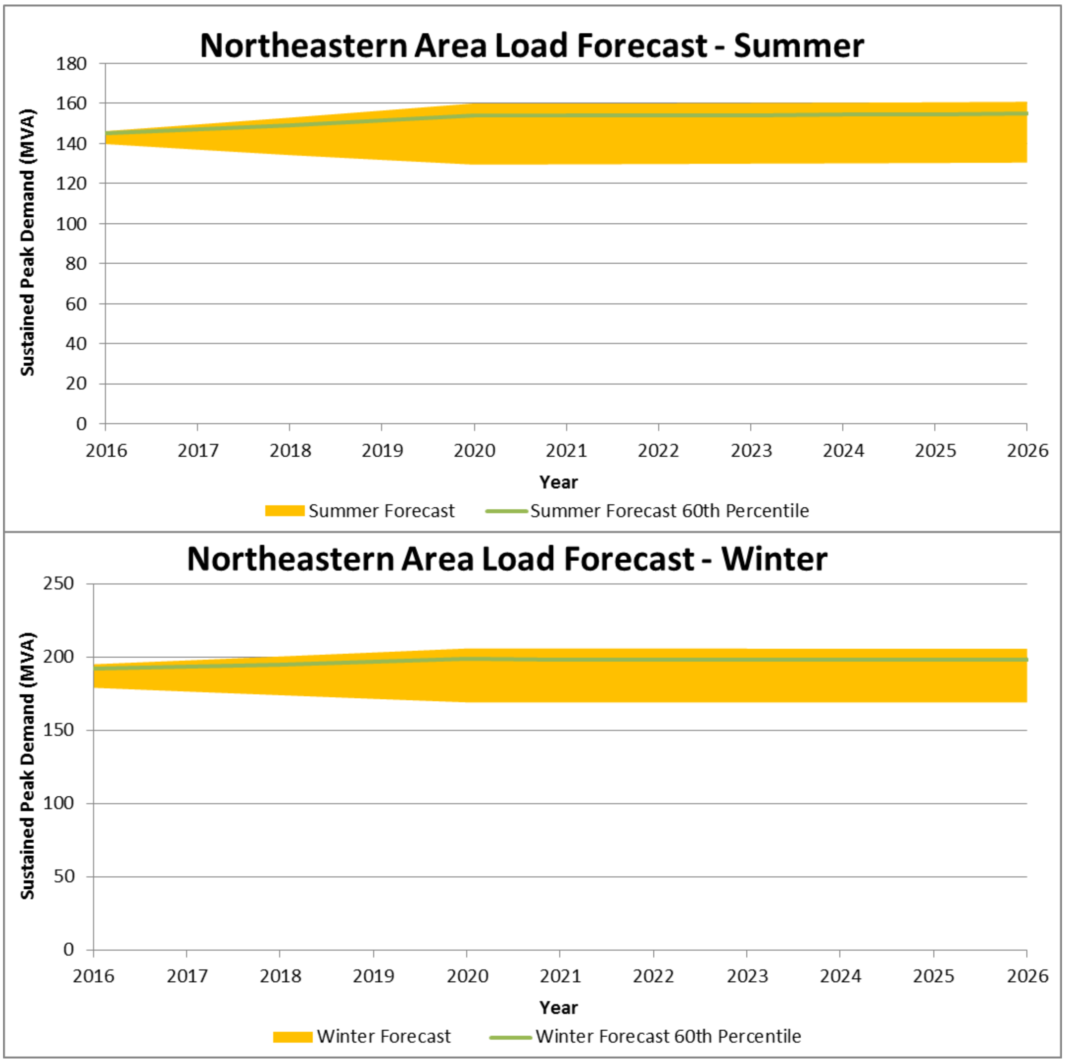


Figure 7-15 Northeastern Area Forecast

7.2.7.6 Step Change Developments

A number of developments are likely within the Northeastern Area, confirmed either through requests received for customer connections or through information requests from developers. The majority of step change loads expected are due to expansion of industrial facilities within the Trentham area.

Expected developments in the Northeastern Area include:

- Expansion of a customer data centre facility which will involve four confirmed stages for a total increase in installed capacity of approximately 4MVA over the next three years. New infrastructure is planned to provide the required capacity and security of supply to these facilities, while also providing increased inter-zone inter-connectivity within the network;

- Redevelopment of an existing industrial premise to house the new Ministry of Primary Industries research centre. A load increase of 1.5MVA is expected within the next two years; and

- A new residential development in the Wallaceville comprising 700 lots that will release 100 sections with an installed capacity of 300kVA per year with an expected maximum demand of 1.2MVA.

A number of smaller fabricating and manufacturing industries have expressed an interest in developing or expanding facilities within the Petone area. The quantity and magnitude of step change demand expected will offset the declining demand from residential and other businesses in the area.

7.2.8 GXP and Zone Level Demand Forecasts

The following tables show the GXP and zone substation level forecast for each Area within the Wellington network. Figure 7-16 shows the GXP level forecast by region and Figure 7-17 shows the Zone substation level forecast by region. For both tables, base maximum demand value for the forecast is for the year ending 31 December 2015 and Area totals are coincident sustained peak demand values.

Area	GXP[32]	Actual and Forecast Sustained Peak Demand MVA[33] 2015 Actual	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Southern	Central Park 33kV	156	155	155	155	155	156	156	157	157	158	158	158
	Central Park 11kV	23	24	24	24	24	24	24	24	24	24	24	24
	Wilton 33 kV[34]	53	52	52	52	52	53	53	53	53	54	54	54
	Kaiwharawhara 11kV[35]	34	35	35	35	35	35	35	35	36	36	36	36
	Area Total	**257**	**255**	**255**	**255**	**256**	**257**	**259**	**260**	**261**	**262**	**263**	**263**
Northwestern	Pauatahanui 33kV	20	20	20	20	20	20	20	21	21	21	21	21

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[32] Transpower's published P90 forecasts at the GXP level allow for a large margin of error, prudent for transmission level planning and as such, are not consistent with Wellington Electricity's forecasts which are less conservative for the purposes of subtransmission and distribution planning.

[33] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections.

[34] Forecast for Wilton 33kV is inclusive of the reduction in load due to Mill Creek export.

[35] Kaiwharawhara GXP has a summer peak. All other stations are winter peaking.

Area	GXP[32]	Actual and Forecast Sustained Peak Demand MVA[33]											
		2015 Actual	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Takapu Rd 33kV	93	93	93	93	94	94	95	95	95	96	96	96
	Area Total	**112**	**112**	**112**	**112**	**112**	**113**	**113**	**114**	**114**	**115**	**115**	**115**
Northeastern	Gracefield 33kV	62	64	64	64	64	64	64	63	63	63	63	63
	Haywards 33kV	15	16	17	17	17	17	17	17	17	17	17	17
	Melling 33kV	35	34	34	34	34	34	34	34	34	34	34	34
	Upper Hutt 33kV	30	30	31	32	32	32	32	33	33	33	34	34
	Haywards 11kV	19	19	19	19	19	19	19	19	19	19	19	19
	Melling 11kV	27	27	28	28	28	28	28	28	28	28	28	28
	Area Total	**187**	**188**	**189**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**

Figure 7-16 Wellington Area GXP Level Forecast

Area	Zone	Actual and Forecast Sustained Peak Demand MVA[36]											
		2015 Actual	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Southern Area	Palm Grove	25	25	25	25	25	25	25	25	25	25	25	25
	Frederick St	29	29	29	29	29	29	29	30	30	30	30	30
	Evans Bay	14	14	14	14	14	14	13	13	13	13	13	13
	Hataitai	20	20	20	20	20	21	21	21	21	21	21	21
	University	25	25	25	25	25	25	25	25	25	25	25	25
	The Terrace	27	27	27	27	27	27	27	27	27	27	27	27
	8 Ira St	18	18	18	18	18	18	18	18	18	19	19	19
	Nairn St	23	24	24	24	24	24	24	24	24	24	24	24
	Karori	18	18	18	18	18	18	18	18	19	19	19	19

[36] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections.

Area	Zone	Actual and Forecast Sustained Peak Demand MVA[36]											
		2015 Actual	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	Moore St[37]	25	25	26	26	27	27	28	28	29	30	30	30
	Waikowhai	16	16	16	16	16	17	17	17	17	17	17	17
Northwestern Area	Mana-Plimmerton	20	20	20	20	20	20	20	21	21	21	21	21
	Johnsonville	17	17	17	17	17	17	18	18	18	18	19	19
	Kenepuru	12	12	12	12	12	12	12	12	12	12	12	12
	Ngauranga	14	14	14	14	14	14	14	14	15	15	15	15
	Porirua	20	20	20	20	20	21	22	22	23	24	24	24
	Tawa	15	15	16	16	16	16	16	16	16	16	17	17
	Waitangirua	15	15	15	15	15	15	16	16	16	16	16	16
Northeastern Area	Gracefield	11	11	10	10	10	10	10	10	10	10	10	10
	Korokoro	19	20	20	20	21	21	21	21	22	22	22	22
	Seaview	16	15	15	15	15	15	15	15	15	15	15	15
	Wainuiomata	17	16	16	16	16	16	16	16	16	16	16	16
	Trentham	14	15	16	17	17	17	17	17	17	17	17	17
	Naenae	15	15	15	15	15	15	15	15	15	15	15	15
	Waterloo	17	16	16	16	16	16	16	16	16	16	16	16
	Brown Owl	15	15	15	15	15	15	15	15	15	16	16	16
	Maidstone	15	15	16	16	16	16	16	16	16	16	16	16

Figure 7-17 Wellington Area Zone Substation Level Forecast

7.3 Overview of the Network Development and Reinforcement Plan (NDRP)

The NDRP describes the identified need, options and investment path for the network over the next 10 years. Each of the three network areas are largely electrically independent and have a different set of challenges. While planning for each network area uses a consistent methodology, they are not all equal in terms of the level of development required. A detailed external review of the development plan has been completed for the Southern and Northwestern Area networks which have higher development needs. A similar external review for Northeastern Area is planned for 2016.

The discussion for each area is structured in accordance with the network hierarchy of GXP level requirements, sub transmission and zone substations and then distribution level investments. The GXP

[37] The Terrace and Moore St zone substations have a summer peak. All other stations are winter peaking.

level discussion has been developed with reference to Transpower's Annual Planning Report and other formal discussions with Transpower regarding their proposed development plans.

The NDRP for each of network area is described the in the following sections.

7.4 Wellington Southern Area NDRP

This section provides a summary of the Southern Area NDRP. It is structured as follows:

- Potential GXP developments;
- Identified subtransmission and distribution development needs and options;
- The network development plan for the planning period; and
- A summary of the expected expenditure profile.

Details of the projects currently in progress or completed in the previous year are described in Appendix C.

7.4.1 GXP Development

The Southern network is supplied from three GXPs, Central Park, Wilton and Kaiwharawhara. The transformer capacity and the maximum system demand are set out in Figure 7-18.

GXP	Installed Capacity (MVA)	Transformer Cyclic N-1 Capacity (Firm Capacity, MVA)	Forecast Maximum Demand (MVA)	
			2016	2026
Central Park 33kV	2x100 + 1x120	200	156	158
Central Park 11kV	2x25	30	24	24
Wilton 33kV	2x100	106	52	54
Kaiwharawhara 11kV	2x40	41	35	36
Total (after diversity)	-	-	**255**	**263**

Figure 7-18 Southern Area GXP Capacities

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Annual Planning Report. Wellington Electricity is currently in discussions with Transpower as to the best solutions to solve the identified issues.

The development need at each GXP is discussed further below.

7.4.1.1 Central Park GXP

The Central Park GXP consists of a sectionalised 33kV bus and 14 subtransmission feeders to seven zone substations, two 33/11kV transformers and an 11kV bus. Each zone substation is supplied from two separate bus sections to provide N-1 redundancy. The 11kV bus at Central Park supplies Nairn Street zone substation. The Central Park GXP risks were discussed in Section 5.9.13.

Wellington Electricity and Transpower have agreed a plan to address risks at Central Park that includes additional risk controls to be implemented during 2016 as well as a list of potentially high cost solutions Wellington Electricity will discuss with stakeholders as part of resiliency work planned in 2016.

7.4.1.2 Wilton GXP

The majority of the Wellington CBD is supplied from the Wilton 110kV bus which has been identified as a high risk. Transpower have also previously identified that the Wilton 110kV bus does not meet grid reliability standards and has a project currently underway to rebuild it as a three-section bus. These works are due to be completed prior to 2017. This will address the supply diversity and resilience concerns at Wilton as each of the three Central Park circuits will be terminated to an individual bus section.

Transpower has also undertaken a risk assessment of a loss of key assets at Wilton, such as the entire 220kV or 110kV bus structures, and has developed concept plans for bypass arrangements that would allow it to restore supply within short timeframes, should such an event occur.

Based on the demand forecasts, the loading will not breach the firm capacity at Wilton during the planning period.

7.4.1.3 Kaiwharawhara GXP

Transpower have no planned works at Kaiwharawhara and based on the demand forecasts, the loading will not exceed the firm capacity at Kaiwharawhara during the planning period.

7.4.2 Subtransmission and Distribution Development Plans

This section describes the identified security of supply constraints and development needs for the Southern Area subtransmission and distribution networks.

The distribution network supplying the Wellington CBD is a highly meshed system with overlapping supply boundaries resulting in a high level of inter-dependency between sites. Development options for the Wellington CBD therefore need to consider these inter-dependencies and the effect on the Wellington CBD network as a whole.

The Southern area network consists of 22 subtransmission 33kV circuits supplying 11 zone substations. Each zone substation supplies the respective 11kV distribution network with inter-connectivity via switched open points to adjacent zones. The characteristics of each zone substation are listed in Figure 7-19.

Zone Substation	Transformer Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Sustained Peak Demand (MVA)		Date Constraints are Binding And season constrained	ICP Counts as at 2016
		Winter	Summer		2016	2026		
Existing								
Frederick St	36	23	20	Winter	29	30	Existing Winter and Summer Constraint	7,649

Zone Substation	Transformer Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Sustained Peak Demand (MVA)		Date Constraints are Binding And season constrained	ICP Counts as at 2016
		Winter	Summer		2016	2026		
Palm Grove	24	34	32	Winter	25	25	Existing Winter Constraint	10,358
University	24	25	20	Winter	25	25	Existing Winter constraint	7,755
Forecasted								
Hataitai	23	22	13	Winter	20	21	2016 Summer constraint	6,873
Moore St	30	36	31	Summer	25	30	2025 Summer constraint	677
Not Constrained								
The Terrace	30	34	32	Summer	27	27	Not Constrained	1,861
Evans Bay	24	19	15	Winter	14	13	Not Constrained	4,733
8 Ira St	24	21	15	Winter	18	19	Not Constrained	4,855
Nairn St	30.1	25	25	Winter	24	24	Not Constrained	5,453
Karori	24	21	11	Winter	18	19	Not Constrained	5,977
Waikowhai St	19	21	13	Winter	16	17	Not Constrained	5,610

Figure 7-19 Southern Area Zone Substation Capacities

At the subtransmission level, Wellington Electricity's planning criteria is to maintain N-1 capacity down to the 11kV incomer level. A typical subtransmission circuit in the area is configured in the following manner:

- Cabling at 33kV to the zone substation supply transformers. This consists of a double circuit arrangement terminating to separate supply transformers. Cables are operated at the cyclic rating. The magnitude of cyclic rating is determined by the ambient temperature (summer and winter) and pre-event loading;

- Zone substation 33kV/11kV supply transformers, in the 20-40MVA range, fitted with oil circulation pumps and cooling fans to provide a higher cyclic rating; and

- 11kV cabling from the 11kV terminations of the transformers to the incomers on the switchboard which can potentially constrain the subtransmission circuit rating if undersized, is also considered a component of the subtransmission circuit.

The development needs for the Southern Area at the subtransmission and distribution level are outlined in the following sections.

7.4.2.1 Subtransmission Development Needs

Subtransmission constraints can be quantified in terms of duration of potential overload and assessed against the security criteria in Figure 7-20, using a load duration curve. Forecasted constraints are quantified in terms of when the risk of overload is likely to occur based on the forecast peak demand for a given year.

The zone substations that are forecast to be beyond N-1 security during the planning period are described below.

Frederick Street

The sustained peak load supplied by Fredrick Street currently exceeds the cyclic N-1 capacity of the subtransmission supply cables. Greater levels of constraint exist in summer than winter due to the relatively high summer peak demand expected in Wellington CBD and the lower summer rating of the cables. The summer peak demand is only marginally less due to the increase in consumption during work hours from large scale cooling and air conditioning plant at commercial premises.

The constraint is due to the heating effects of the two cables being in close proximity to each other at a pinch point in the streets of Wellington CBD. Work was undertaken in late 2015 to mitigate most, but not all, of the constraining sections. These works have resulted in an increase in the cyclic capacity of the Frederick Street subtransmission cables, from 17/21MVA (summer/winter cyclic rating) to 19.5/23.2MVA. The maximum demand at Frederick Street is still in excess of the subtransmission cable capacity.

Figure 7-20 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
Frederick St 1	Winter	23.2	28.56	5.5
	Summer	19.5	26.13	7
Frederick St 2	Winter	23.2	28.56	5.5
	Summer	19.5	26.13	7

Figure 7-20 Current Frederick Street Subtransmission Constraints

Following a fault on the subtransmission system, Wellington Electricity currently close the 11 kV bus tie and restores supply to consumers through partially off-loading Frederick Street to an alternative zone substation.

Future step change loading on feeders inter-connecting with Frederick Street will reduce the available transfer capacity and post contingency offload will become difficult.

Figure 7-21 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable.

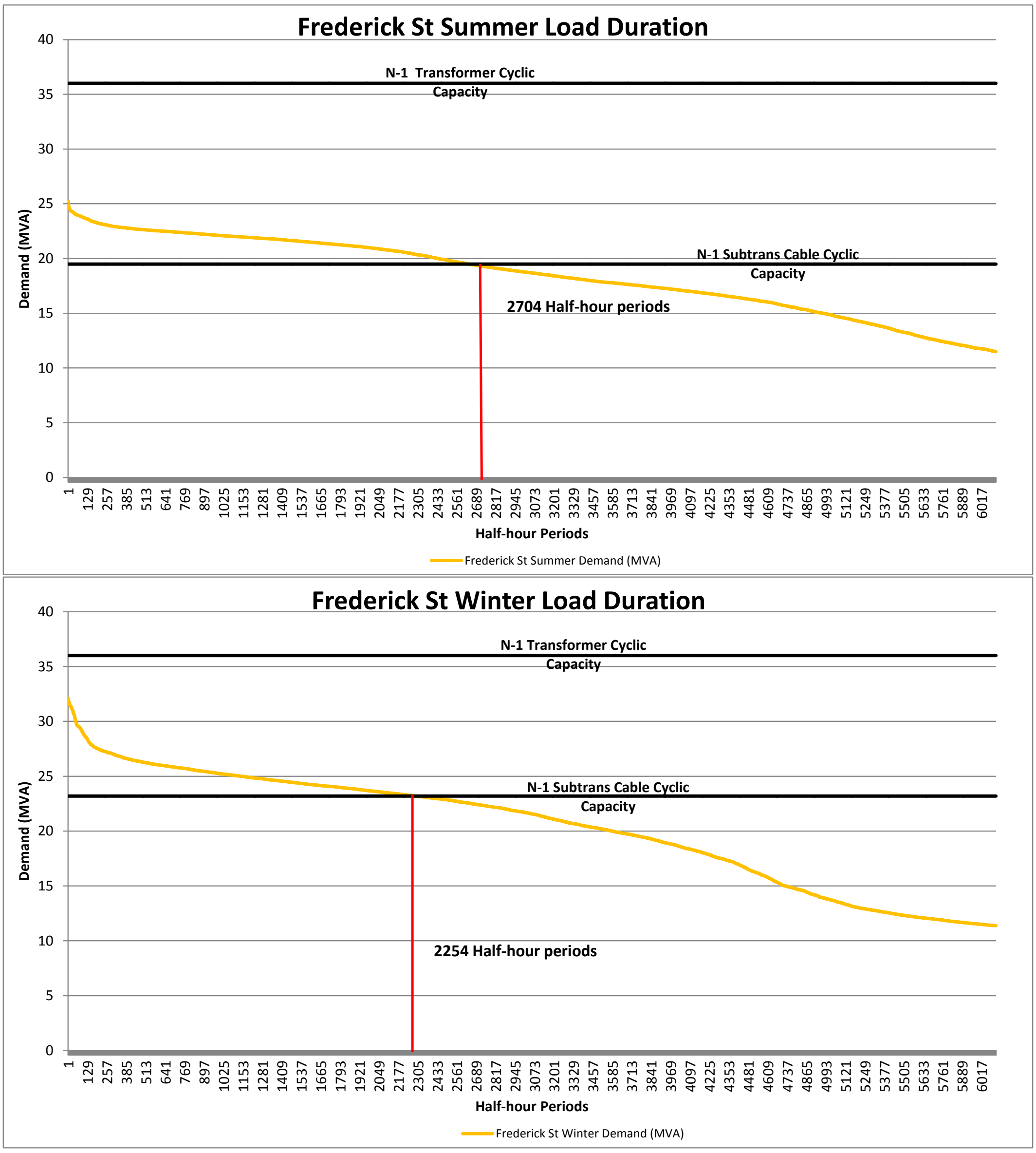


Figure 7-21 Frederick Street Load Duration

The load duration curve shows that a significant proportion of load is at risk. The loading exceeds the cable's N-1 summer cyclic rating for approximately 15.4% of the time in summer and the cable's N-1 winter cyclic rating for approximately 12.8% of the time in winter. This analysis uses a load duration curve based on 30 minute periods and is higher than the sustained peak.

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Frederick Street is forecasted to change as shown in Figure 7-22. The subtransmission capacity constraints are plotted for comparison.

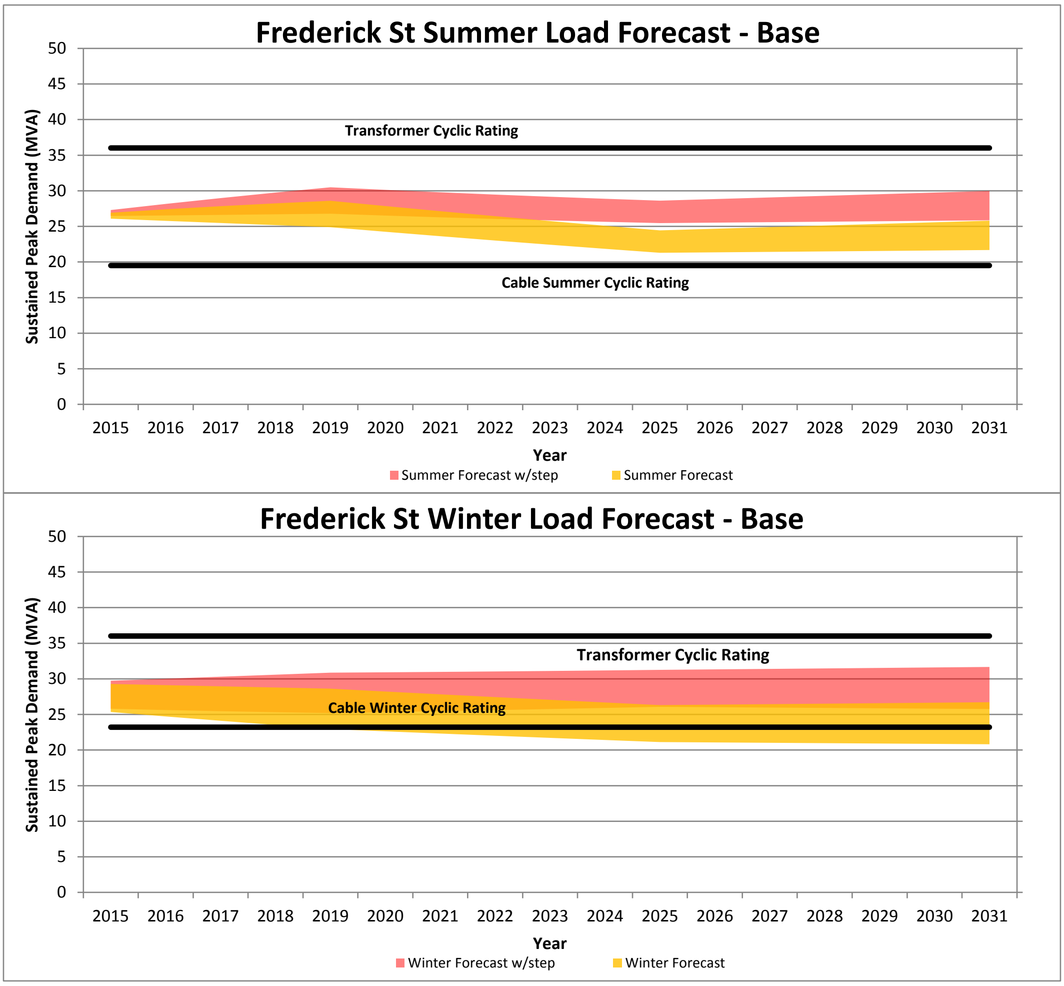


Figure 7-22 Frederick Street Load Forecast

Palm Grove

The sustained peak demand at Palm Grove currently exceeds the capacity of the two 24MVA transformers as illustrated in Figure 7-23.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
Palm Grove 1	Winter	24	25	1
	Summer	24	18	0
Palm Grove 2	Winter	24	25	1
	Summer	24	18	0

Figure 7-23 Current Palm Grove Subtransmission Constraints

Following an outage of a single subtransmission circuit at Palm Grove during peak demand periods, the bus-tie is closed and switching is performed to move load to adjacent zones.

The back-feed switching must also be sequenced to maintain supply to Wellington Hospital as supply interruptions of any duration to the hospital are unacceptable. Wellington Electricity has been in discussions with the Capital Coast District Health Board about the potential options for mitigating the security of supply and resilience risks at Wellington Hospital.

Wellington Hospital have also previously indicated high level plans to expand facilities within the planning period. The capacity and timing of these expansion plans are not yet confirmed.

The magnitude of load at risk and duration is summarised in Figure 7-24.

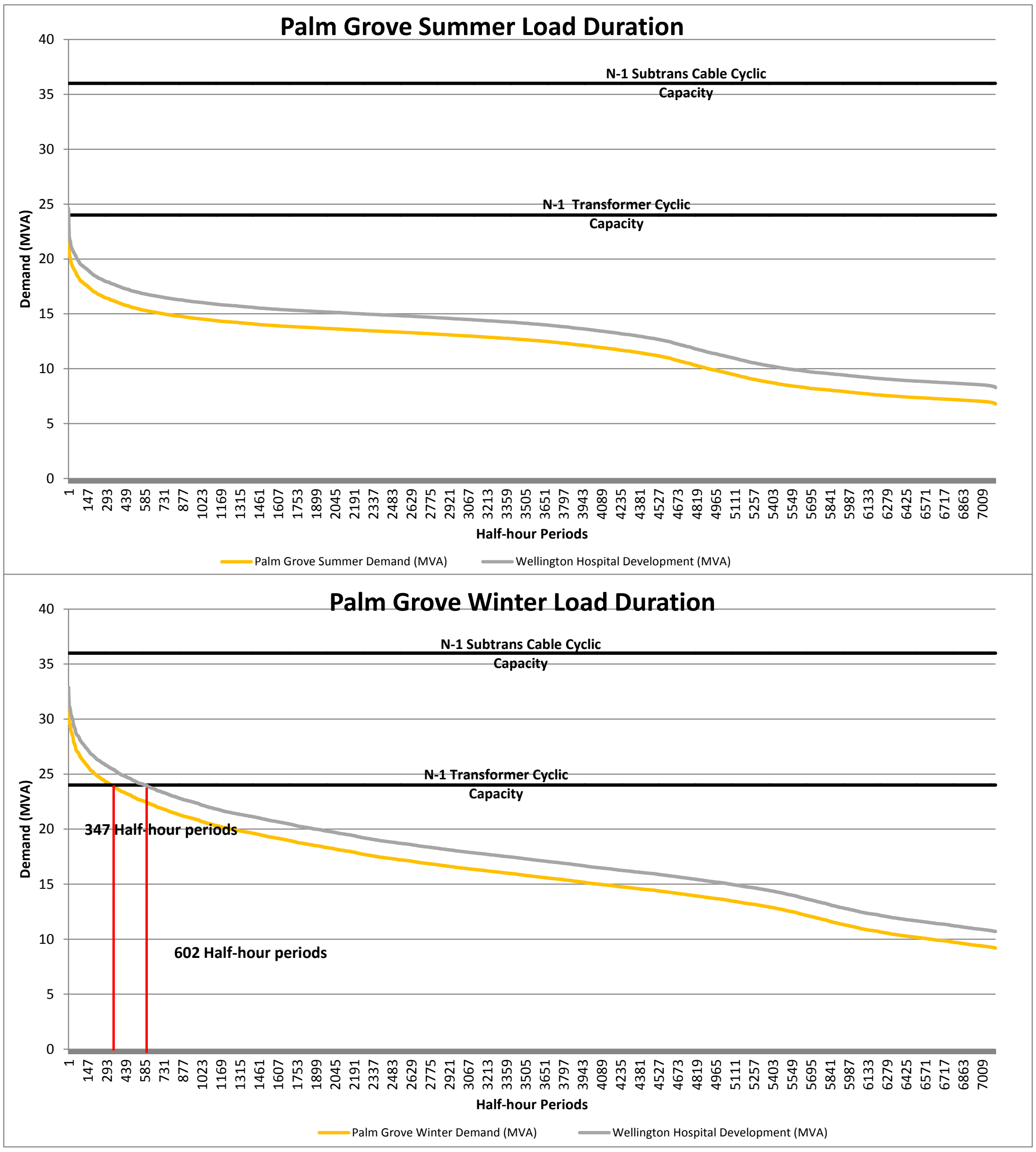


Figure 7-24 Palm Grove Load Duration

The sustained peak demand loading during winter exceeds the N-1 transformer cyclic capacity for approximately 1.98% of the time during winter. This exceeds the security criteria for a CBD zone substation. The magnitude of this breach is expected to increase due to organic and step change load growth (with the impact of the hospital load increases shown in grey in Figure 7-24). This load duration curve is based on 30 minute periods and is higher than the sustained peak.

Based on the growth scenarios and the development accounted for within the planning period, the load at Palm Grove is forecasted to grow as shown in Figure 7-25. An allowance for the step change at Wellington Hospital has been included.

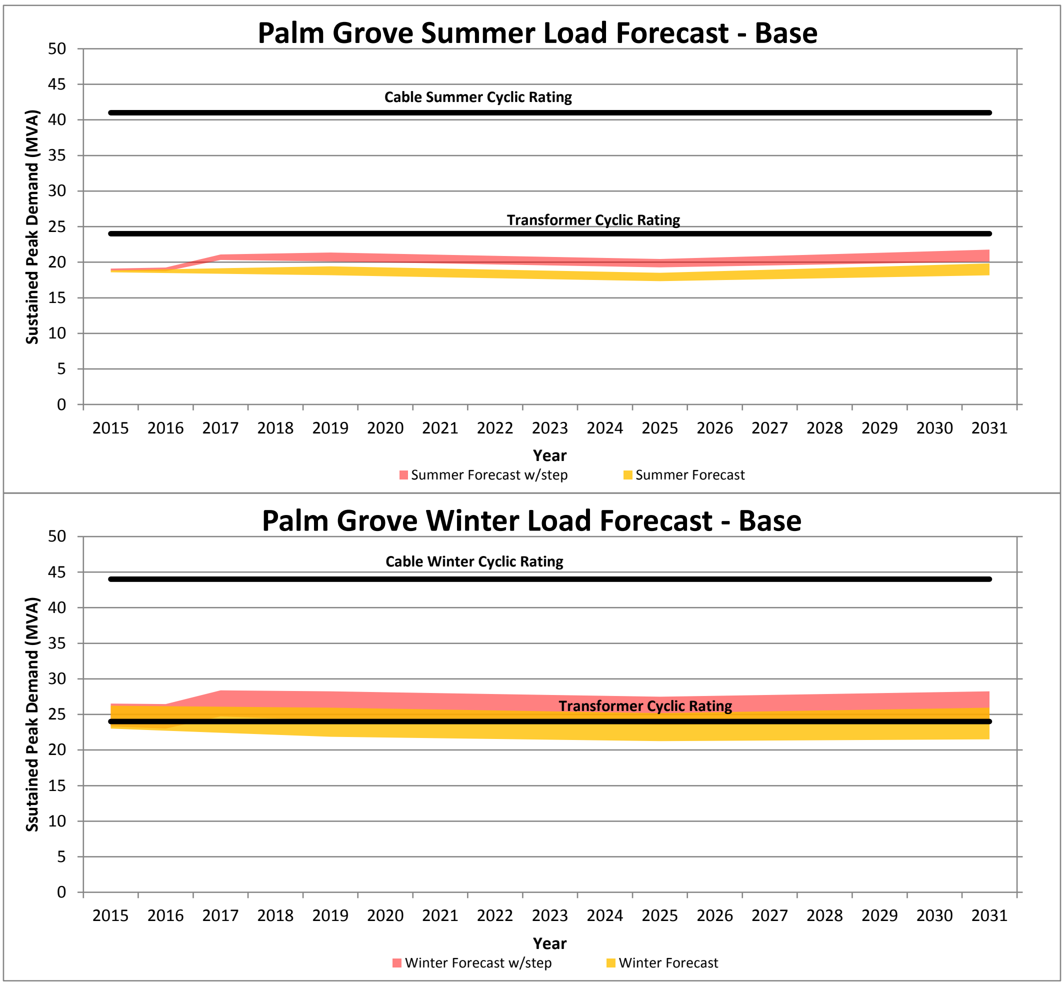


Figure 7-25 Palm Grove Load Forecast

University

The sustained peak demand supplied by University currently exceeds the cyclic N-1 capacity of the subtransmission transformers in the summer and the cyclic capacity of both the transformers and cables in winter. This is within the security criteria as illustrated in Figure 7-26 and is likely to increase due to expected development at Victoria University.

Following a fault on the subtransmission system, Wellington Electricity currently closes the 11 kV bus tie and restores supply to consumers through partially off-loading the University substation feeders to an alternative zone substation.

Circuit	Season	Constraining N-1 Cyclic Capacity (MVA)	Sustained Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
University 1	Winter	24	25.2	1-2MVA
	Summer	20	19.82	-
University 2	Winter	24	25.2	1-2MVA
	Summer	18	19.82	1-2MVA

Figure 7-26 Current University Subtransmission Constraints

The magnitude of load at risk and duration is summarised in the load duration curves shown in Figure 7-27. An approximation of the step change demand due to development at Victoria University (2.5MVA at their Kelburn Campus) has been incorporated.

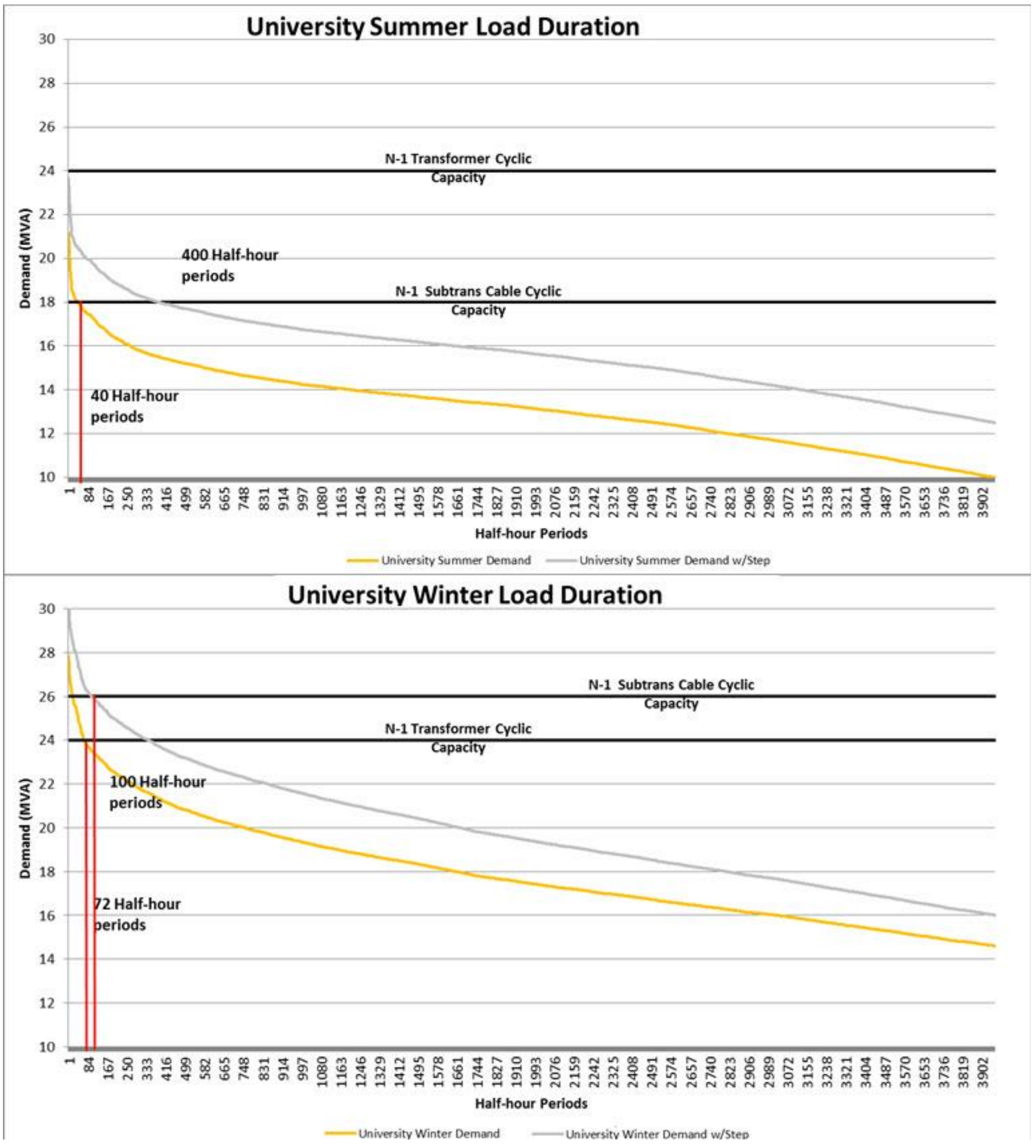
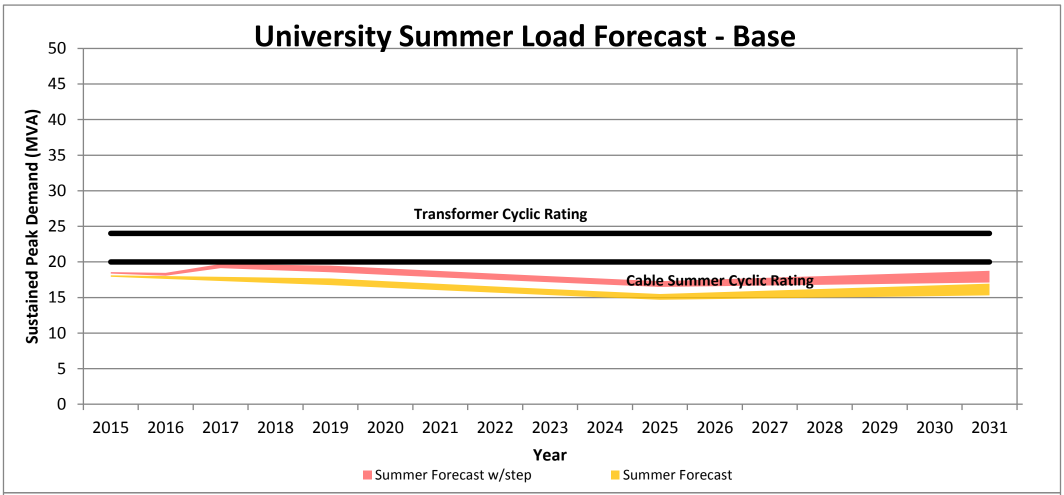


Figure 7-27 University Load Duration Curve

The loading at University is shown to exceed the available N-1 capacity for approximately 0.41% of the time in a year or 1.9% of the time in a year when considering the expected step change demand due to development at Victoria University.

The condition of the XLPE cable is poor and show signs of premature aging due to overheating. This is discussed further in Section 6.

The forecasted growth rates and confirmed step load change at Victoria University are shown in Figure 7-28.



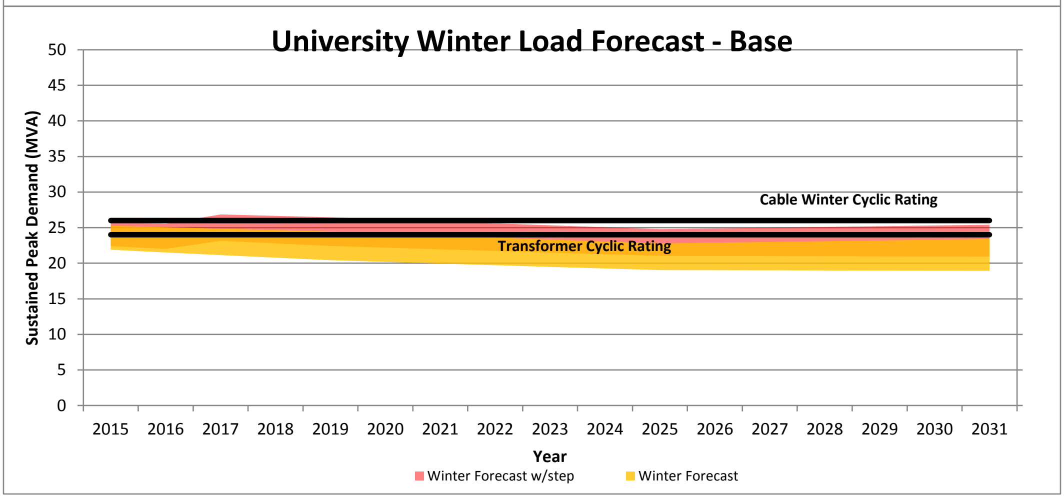


Figure 7-28 University Load Forecast

Hataitai

The sustained peak demand supplied by Hataitai currently exceeds the cyclic N-1 capacity of the subtransmission supply cables. Following a loss of a single subtransmission circuit at Hataitai, the bus-tie is closed and the single remaining incomer supplies the entire 11 kV bus at Hataitai.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
Hataitai 1	Winter	22	19.48	-
	Summer	13	13.19	Negligible
Hataitai 2	Winter	22	19.48	-
	Summer	13	13.19	Negligible

Figure 7-29 Hataitai Subtransmission Constraints

At present, the duration for which the loading at Hataitai just exceeds the available N-1 subtransmission cyclic capacity during summer is within the security criteria. It is expected that organic load growth at Hataitai will result in exceeding the security criteria within the next two years.

The forecasted sustained peak demand at Hataitai is shown in Figure 7-30.

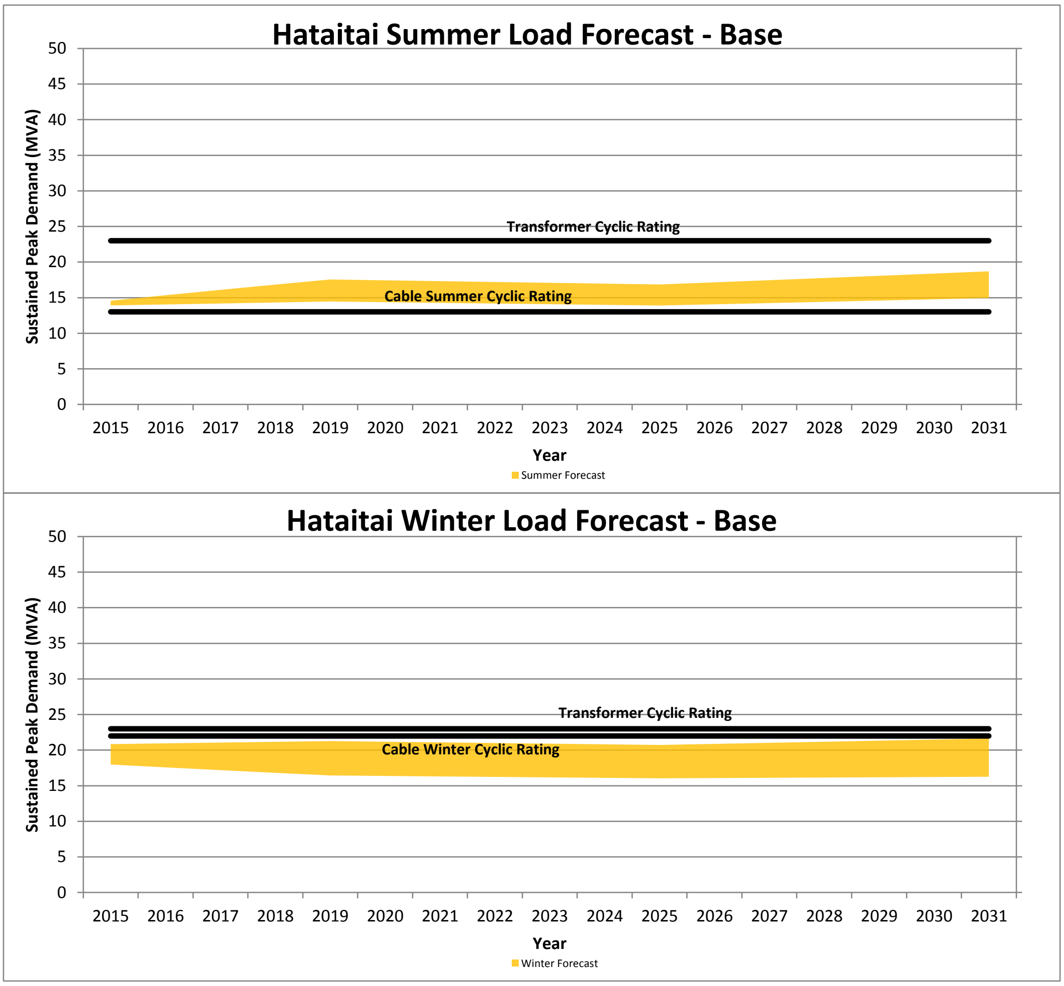


Figure 7-30 Hataitai Demand Forecast

Moore Street

The peak sustained demand supplied by Moore Street is currently within the available N-1 capacity of the subtransmission circuits supplying the zone substation. This is illustrated in Figure 7-31.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
Moore Street 1	Winter	30	21	0
	Summer	30	25	0
Moore Street 2	Winter	30	21	0
	Summer	30	25	0

Figure 7-31 Current Moore Street Subtransmission Constraints

The organic load growth at Moore Street is forecasted to increase the sustained peak demand to 30MVA by 2026. There are a number of step change loads expected during the planning period as discussed above. Load growth at Moore Street is expected to exceed the N-1 ratings of the transformers by 2018 as illustrated in Figure 7-32.

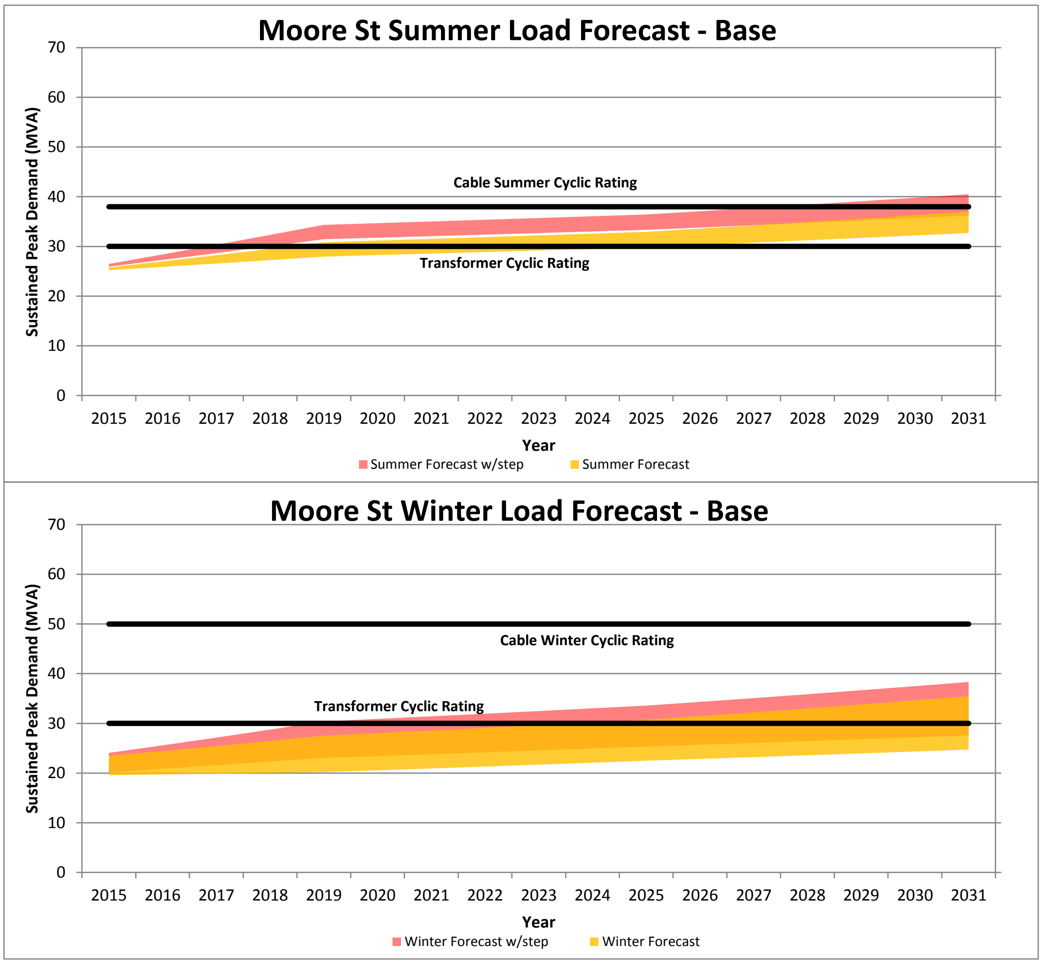


Figure 7-32 Moore Street Load Forecast

7.4.2.2 Distribution Level Development Needs

The most critical distribution level issues are those associated with:

- meshed ring feeders supplying a high number of customers; and
- links between zone substations, which can be used for load transfer.

Figure 7-33 shows the current and forecast loading for each feeder. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder the steady state control that has been applied to manage any risks that might arise has been provided.

Feeder	Topology	Zone Substation	Worst case loading @	Present Loading	+10 years	Feeder ICP Count	Control
Current							
FRE CB13	2 Fdr Mesh	Frederick Street	21 Tasman St	79%	70%	1,342	Network augmentation
PAL CB12	3 Fdr Mesh	Palm Grove	The Parade	66%	67%	867	Monitor growth
UNI CB13	Radial	University	33 Kelburn Pde	77%	70%	N/A[6]	Monitor growth
IRA CB12	Radial	8 Ira Street	Devonshire Rd	67%	73%	N/A[6]	Monitor growth
KAR CB03	2 Fdr Mesh	Karori	Dasent St	90%[3]	76%	535	Open point shift
KAR CB06		Karori	Burrows Ave	73%[3]	Less 66%	2,238	
WAK CB04	3 Fdr Mesh	Waikowhai	Orari St	69%[2]	79%	1,647	Monitor growth
KAI CB06	4 Fdr Mesh	Kaiwharawhara	Abbatoirs West	100%[4]	100%	429	Customer initiated project
TER CB15	Radial	The Terrace	88 Boulcott St	66%	71%	269	Monitor growth
Within Five Years							
PAL CB02[5]	3 Fdr Mesh	Palm Grove	312 Adelaide Rd	Less 66%	86%[7]	1,376	Network augmentation
PAL CB03[5]		Palm Grove	415 Adelaide Rd	Less 66%	68%[7]	1,101	
PAL CB06[5]		Palm Grove	Mansfield St	Less 66%	84%[7]	1,436	
MOO CB09	Radial	Moore Street	47 Thorndon Quay	Less 66%	74%	150	Monitor growth
MOO CB12	2 Fdr Mesh	Moore Street	55 Aotea Quay	Less 50%	70%[7]	76	Network augmentation
MOO CB14		Moore Street	50 Thorndon Quay	Less 50%	94%[7]	522	

Figure 7-33 Distribution Level Issues

Notes to Figure 7-33

1. Acceptable normal operation peak loading as a percentage of capacity, as per planning criteria in Figure 7-2. Contingency analysis for mesh feeder configurations provided in Figure 7-3.
2. Undersized cable segment.
3. Due to 9 Parkvale Road switchgear replacement and network reconfiguration.
4. Recommendation has been developed for customer to alleviate loading.
5. Palm Grove 2/3/6 ring supplies the Wellington Hospital.
6. Recent reconfiguration of feeders, ICP count are not available.
7. Due to potential step change in the area.

Overloads on feeders supplied from Nairn Street, Karori and Evans Bay decline from year to year due to the declining loads in these areas.

Cascade tripping of ring feeders for a loss of a single component feeder is a possibility due to the overcurrent settings applied at the zone substation. Settings are typically set for protection of the feeder breaker and an allowable short time overload of the cables. The sudden loss of a single feeder may result in the transfer of sufficient load to the remaining feeders and should not cause a trip of the feeder protection relays at the zone substation. Each subsequent trip would results in further overload of the remaining feeders. The result is the possible loss of the entire mesh ring and possible equipment and cable damage due to overloading prior to the protection devices clearing.

Figure 7-34 shows the results of the contingency analysis performed on all meshed ring feeders in the Southern Area currently above the security criteria. Scenarios with overloading feeder segments for each contingency scenario are shown as well as the prospective location and loading. The contingency loading calculation is based on the sustained peak demand for each feeder recorded for 2015.

Meshed Ring	N-1 Case	Feeder	To	From	Contingency Loading	Control
FRE 3/4/5/6	FRE CB08 Out	FRE CB04	106 Tory St	21 Tory St	106.34%	Optimise open points and monitor growth
FRE 13/14	FRE CB13 Out	FRE CB14	Frederick St CB14	19 College St	116.26%	Network augmentation
	FRE CB13 Out	FRE CB13	Frederick St CB13	21 Tasman St	128.10%	
PAL 2/3/6	PAL CB02 Out	PAL CB03	130 Rintoul St	Newtown	119.20%	Network augmentation
	PAL CB03 Out	PAL CB02	Palm Grove CB02	312 Adelaide Rd	105.15%	
	PAL CB06 Out	PAL CB02	Palm Grove CB02	312 Adelaide Rd	102.44%	
		PAL CB03	Riddiford Rd	74 Riddiford Rd	105.42%	
PAL 8/10/12	PAL CB08 Out	PAL CB10	Herald St	37 Mersey St	125.20%	Network augmentation
UNI 8/10	UNI CB08 Out	UNI CB10	University CB10	Military Rd	125.20%	Optimise open points and monitor growth
		UNI CB11	University CB11	Chaytor St	124.80%	

Meshed Ring	N-1 Case	Feeder	To	From	Contingency Loading	Control
NAI 8/12	NAI CB08 Out	NAI CB12	Nairn St CB12	Webb St	105.69%	Optimise open points and monitor growth
	NAI CB12 Out	NAI CB08	Nairn St CB08	Arthur St	107.32%	

Figure 7-34 Meshed Ring Feeder Contingency Analysis

7.4.3 Southern Area Subtransmission and Distribution Development Options

This section summarises the options available to meet the development needs described above.

As the distribution network within the Southern Area is highly meshed the development options for the Wellington CBD are comprised of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive and as such there are options which meet several needs for the same investment. In the 2015 AMP four options were presented to address the identified needs at the time. These have been further reviewed and refined, and two development options have been identified as being the most practical within the planning period.

7.4.3.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions to defer investment. These options include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over construction of redundant capacity; and
- Consideration of the cost effectiveness of demand side management to alleviate localised network constraints.

These non-network solutions will be implemented prior to any network investment. Wellington Electricity currently monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets. Where thermal overload limits are at risk of being exceeded, network controllers are able to:

- Initiate shedding of hot water load to provide peak shaving during peak demand periods; and
- Fine tune network open points to optimise feeder loading and feeder customer numbers.

7.4.3.2 Network Investment Options

Common Development Projects

A number of projects within the Wellington CBD will be required to augment the network and improve security of supply. These projects are required irrespective of the development option selected and are as follows:

- A new feeder from Moore Street to reinforce the Moore Street 12/14 ring feeder, interconnecting with feeders from Kaiwharawhara and supplying Westpac Stadium and Centerport;

- Balancing bus section load at a number of zone substations, which will involve physically swapping feeders between the two bus sections;
- The installation of a new 33kV bus at Evans Bay to supply Evans Bay and Ira Street zone substations. This new 33kV bus will be supplied from the Ira Street oil filled cables and one of the existing Evans Bay cables and will defer replacement of the other Evans Bay cable which is in poor condition. Although this investment has a condition based driver, it has been included in the network development section because of its impact on the configuration of the 33kV subtransmission network;
- Installation of bus-tie changeover schemes at all zone substations in the Southern Area to allow rapid restoration of supply following subtransmission faults; and
- Reduction or limitation of fault levels at all zone substations in the Southern Area.

Southern Area Development Options

Following the refinement of the options identified in the 2015 AMP, two development options have been further developed and evaluated against the development needs described in Sections 7.4.2.1 and 7.4.2.2.

The two refined development options assessed for the planning period are:

- Option 1: Installation of a new zone substation supplied from Central Park GXP with distribution level interconnections to The Terrace, Frederick Street and Palm Grove; and
- Option 2: Augmentation of the existing subtransmission and distribution infrastructure to alleviate constraints and improve transfer capacity.

Two studies were commissioned to determine costing and feasibility to a higher degree of confidence such that an informed decision can be made as to the recommended development path. These studies were:

- Feasibility and cost estimation of establishing a new zone substation within the CBD;
- Review and cost estimation of the Network Development and Reinforcement Plan and all component projects for the two options listed above.

Each of the options is described in more detail below.

Option 1: Installation of a New Zone Substation

This option involves installation of a new zone substation, supplied from Central Park GXP. The new zone substation would have distribution feeders inter-connecting with Frederick Street, Kaiwharawhara and Palm Grove. The proposed distribution connectivity is to ensure this option will mitigate the identified issues with an integrated solution.

Load would be permanently transferred from the highly loaded feeders from Palm Grove and Frederick Street to the new zone substation. This would have the effect of alleviating loading constraints at the distribution and subtransmission level at both of these sites.

Figure 7-35 illustrates the final configuration of Option 1.

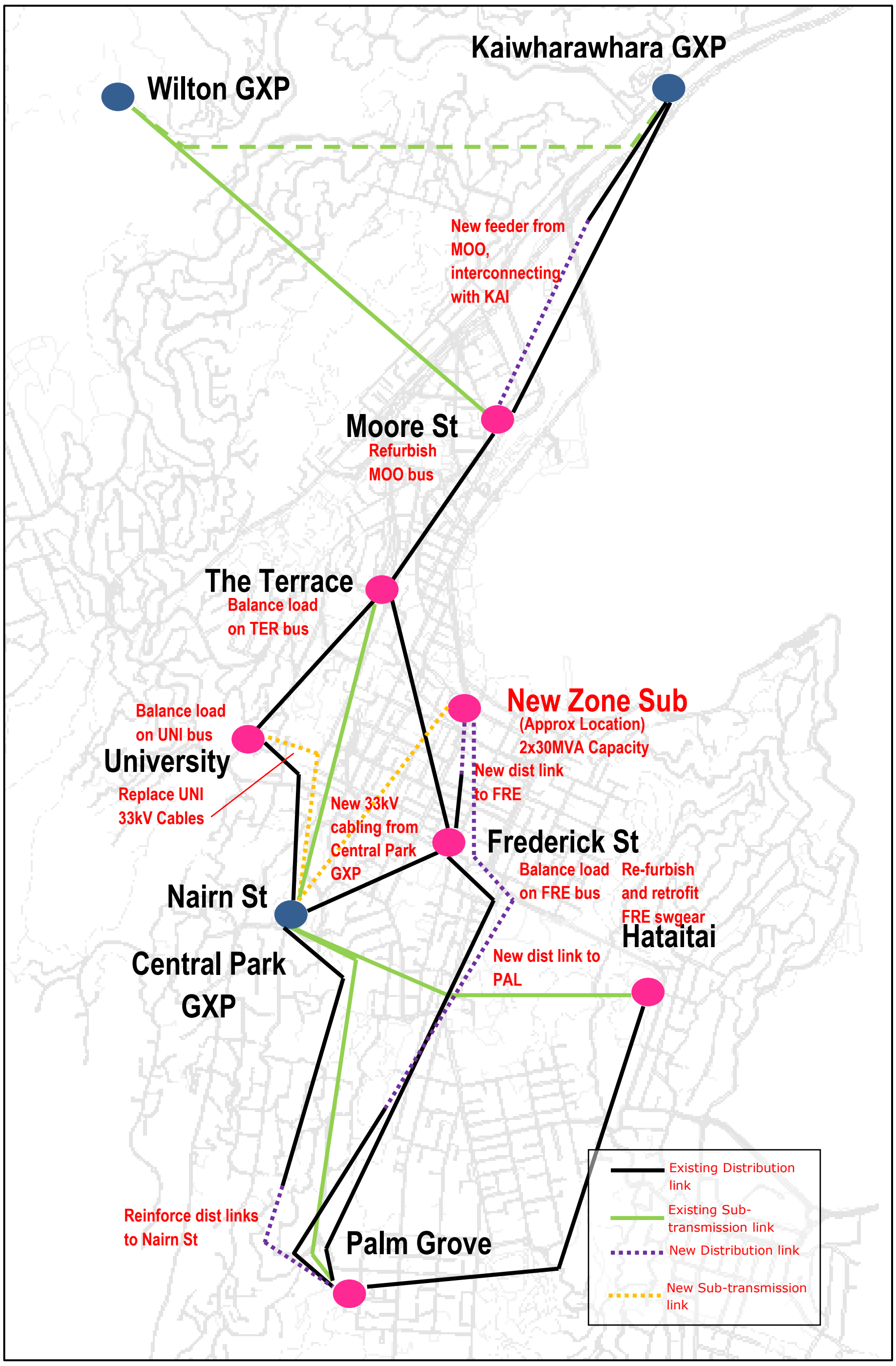


Figure 7-35 Proposed Configuration for Option 1

The implementation of the option would be staged to align with the timing of constraints as they arise.

A pre-feasibility study into establishing a new zone substation in the CBD has provided a +/- 30% cost estimate for the zone substation component of this option. The separate external review of the NDRP has provided more detailed costing (+/-30%) of all subtransmission and distribution works required in addition to the establishment of the new zone substation. The cost of this network development option is shown in Figure 7-36.

Project Description	Cost ($M)
Construction of a zone substation within the CBD (+/- 30%) and network reinforcement	22.4
Planned common projects for both options	13.0
Total Southern Area NDRP Investment - Option 1	**35.4**
Condition-based Asset Renewal Expenditure	9.0
Comparative NPV (total cost less common projects plus renewal expenditure*)	20.9

Figure 7-36 Estimated Cost of Network Development Option 1

*Note: The asset renewal expenditure under Option 1, used in the NPV analysis is $9 million. This is lower than accounted for in Option 2 ($12.5 million), as it reduces the criticality of a number of switchboards in the CBD, allowing capital expenditure deferral.

Option 2: Subtransmission & Distribution Level Augmentation

Option 2 involves augmentation of the subtransmission and distribution networks to alleviate the identified issues. It provides for distribution reinforcement projects to improve capacity and security of supply. Subtransmission issues are mitigated through load transfer to adjacent zone substations or by upgrading asset capacity.

This option includes:

- Replacing the subtransmission cables to Frederick Street with new high capacity XLPE cables. These cables will offer sufficient capacity to cater for the expected growth at Frederick Street while also providing redundant capacity for contingency operation.
- Alleviating the issues at Palm Grove in isolation from the rest of the network. Further subtransmission capacity is provided by replacing the Palm Grove transformers with two new 30MVA units (36MVA cyclic). The Palm Grove 2/3/6 feeder ring is to be reconfigured and reinforced to alleviate loading on this distribution ring and improve security of supply to Wellington Hospital and the Newtown area. The existing inter-connections between Palm Grove and Nairn Street are reinforced to provide post-contingency transfer capacity for a subtransmission fault at Palm Grove.

Figure 7-37 provides a visual representation of the end product of this development path.

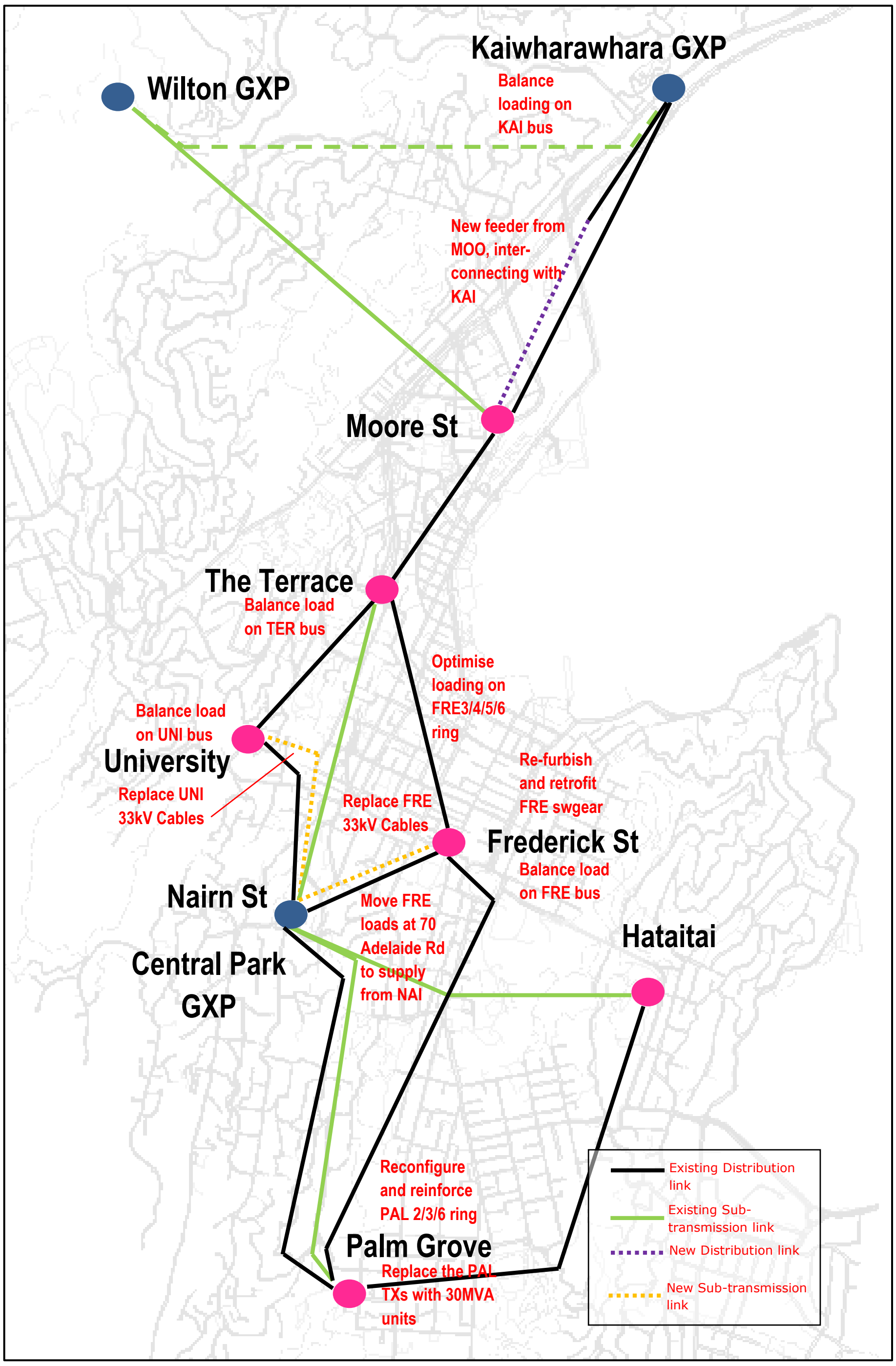


Figure 7-37 Proposed Configuration for Option 2

The estimated cost of implementation of this network development option is shown in Figure 7-38.

Project Description	Cost ($M)
Total marginal cost of network reinforcement for capacity	12.9
Planned common projects for both options	13.0
Total Southern Area NDRP Investment - Option 2	**25.9**
Condition-based Asset Renewal Expenditure	12.0
Comparative NPV (total cost less common projects plus renewal expenditure*)	15.4

Figure 7-38 Estimated Cost of Network Development Option 2

7.4.4 The Southern Area Development Plan

Option 2 is the most cost effective option which mitigates all identified issues while also ensuring a balanced network and complementing Transpower's position

It has the benefit of introducing high capacity ties between critical zone substations as well as increasing capacity and replacing aging subtransmission assets. It involves the following major milestones and timing of works to mitigate the identified constraints in the most feasible and cost effective manner:

- **2016** - Open point shifts to temporarily alleviate distribution level constraints and defer network investment till 2017/18;
- **2018/19** – Replacement of the Frederick Street gas filled subtransmission cables with new high capacity XLPE cables to improve capacity at Frederick Street; and
- **2019** – Replacement of the transformers at Palm Grove with higher capacity units. The ex-Palm Grove units will be relocated and installed at Evans Bay to replace the existing transformers at this station. The feasibility of these works will be investigated further in 2016. Reinforcement of the Palm Grove zone 1 distribution ring.

The majority of identified feeder loading risks will be eliminated by the end of the planning period. A number of feeder overloads at Moore Street, Palm Grove and Nairn Street are accepted on the basis of the ability to enact contingency load shifts to an adjacent zone following retrofit of remote switching and telemetry to a number of network critical distribution switching points throughout the network.

Condition based asset replacement/refurbishment projects identified in this development plan are discussed further in Section 6.

7.4.5 Summary of the Southern Area Investment

Figure 7-39 shows the investment plan projects in the Wellington Southern area for the planning period from 2016-2026. Further detail of each project is provided in Appendix C.

Year	Project	Estimated Cost ($M)	Comments
2016	Frederick Street bus-tie change-over scheme	0.07	Common Project
	Allowance for minor cable reinforcement works	0.2	NDP Option 2
2017	Evans Bay 33kV Bus – Year 1	3.5	Common Project
	Bus-tie changeover implementation (3-4 sites per year)	0.3	Common Project
	Allowance for minor cable reinforcement works	0.4	NDP Option 2
2018	Evans Bay 33kV Bus – Year 2	1.0	Common Project
	Frederick Street Subtransmission Cable Replacement and Protection Upgrade – Year 1	2.5	NDP Option 2
	Bus-tie changeover implementation (3-4 sites per year)	0.3	Common Project
	Allowance for minor cable reinforcement works	0.2	NDP Option 2
2019	Frederick Street Subtransmission Cable Replacement and Protection Upgrade – Year 2	1.6	NDP Option 2
	Moore Street - New Feeder	1.8	Common Project
	Replacement of the Palm Grove Transformers (capacity driven)	3.1	NDP Option 2
	Bus-tie changeover implementation (3-4 sites per year)	0.3	Common Project
	CBD substation bus fault level improvements	0.9	Common Project
	Allowance for minor cable reinforcement works	0.2	NDP Option 2
2020	Balance loading on Kaiwharawhara bus	0.1	NDP Option 2
	Bus-tie changeover implementation (3-4 sites per year)	0.3	Common Project
	CBD substation bus fault level improvements	0.9	Common Project
2021	Palm Grove Zone 1 Ring Reinforcement - Stage 1	1.1	NDP Option 2
	CBD substation bus fault level improvements	0.9	Common Project
2022	Balance loading on Frederick Street bus	0.1	NDP Option 2
	Palm Grove Zone 1 Ring Reinforcement - Stage 2	1.2	NDP Option 2

Year	Project	Estimated Cost ($M)	Comments
	CBD substation bus fault level improvements	0.9	Common Project
2023	Palm Grove Zone 1 Ring Reinforcement - Stage 3	2.2	NDP Option 2
	CBD substation bus fault level improvements	0.9	Common Project
2024	CBD substation bus fault level improvements	0.9	Common Project
	Total Investment	**25.9**	

Figure 7-39 Summary of Southern Area Investment Requirement ($M in constant prices)

7.5 Northwestern Area NDRP

Porirua City looking north (photography credit: Porirua City Council)

This section provides a summary of the Northwestern Area NDRP. This section is structured as follows:

- Identified GXP development needs;
- Identified subtransmission and distribution level development needs and options;
- The network development plan for the planning period; and
- A summary of the expected expenditure profile.

Detail of each project in the development plan is described in Appendix C.

7.5.1 GXP Development

The Northwestern Area is supplied from two GXPs, Pauatahanui and Takapu Road. The transformer capacity and the sustained maximum demand are set out in Figure 7-40.

GXP	Installed Capacity (MVA)	Firm Capacity (MVA)	Forecast Sustained Maximum Demand MVA	
			2016	2026
Takapu Rd 33kV	2x90	123	93	96
Pauatahanui 33kV	2x20	24	20	21

Figure 7-40 Northwestern Area GXP Capacities

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Annual Planning Report. Wellington Electricity is currently in discussions with Transpower as to the best solutions to solve the identified issues.

The development need at each GXP is discussed further below.

Takapu Road

The Takapu Road GXP comprises two parallel 110/33kV transformers each nominally rated at 90 MVA with a potential N-1 cyclic capacity of 123MVA. The sustained maximum demand on the Takapu Road GXP in 2015 was 93MVA. Takapu Road supplies zone substations at Waitangirua, Porirua, Kenepuru, Tawa, Ngauranga and Johnsonville each via double 33 kV circuits.

Wellington Electricity began execution of a staged programme to replace the aging protection devices on the subtransmission circuits supplied from Takapu Road.

The Ngauranga subtransmission circuits from Takapu Rd GXP are 110kV lines, operating at 33kV, installed on steel pylon towers and owned and maintained by Transpower. A number of factors need to be considered in determining the long term viability of this arrangement such as:

- Maintain status quo;
- Transpower's preference to decommission the overhead lines in the future;
- Wellington Electricity taking ownership of the 110kV lines; or
- The possibility of undergrounding the lines from Takapu Road.

Pauatahanui

Due to works to transfer the Paraparaumu GXP to a new tee off point on the Bunnythorpe-Haywards 220kV lines, Pauatahanui is now solely supplied from the Takapu Road GXP via two 110kV circuits. With the removal of Paraparaumu from the 110kV network, these circuits are significantly over rated for Pauatahanui requirements.

Pauatahanui GXP comprises two parallel 110/33kV transformers rated at 20MVA each. The maximum peak demand on the Pauatahanui GXP in 2015 was 20MVA. This is within the transformer emergency ratings and also the winter cyclic rating of 24MVA. 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.

Transpower has identified that the Pauatahanui supply transformers are approaching end-of-life and that replacement will be required within the next 5-10 years, which coincides with the site loading exceeding the N-1 rating. At the time of replacement a capacity upgrade may be required, with the future ratings still to be determined. Wellington Electricity will discuss with Transpower the potential options for alleviating or replacing the Pauatahanui supply transformers.

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

7.5.2 Subtransmission and Distribution Development Plan

This section describes the identified security of supply constraints and development needs for the Northwestern Area subtransmission and distribution networks.

The Northwestern network consists of 12 subtransmission 33kV circuits supplying seven zone substations. Each zone substation supplies the respective zone 11kV distribution network with inter-connectivity via switched open points to adjacent zones. All 11kV feeders are radial from the zone substations with the exception of the meshed ring feeders supplying the Porirua CBD and the Titahi Bay switching station. The characteristics of each zone substation are listed in Figure 7-41.

Zone Substation	Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Sustained Peak Demand (MVA)		Date Constraints are Binding And season constrained	ICP Counts as at 2016
		Winter	Summer		2016	2025		
Existing								
Ngauranga	12	20	14	Winter	14	15	Existing Winter constraint	5,483
Mana-Plimmerton	16	27	34	Winter	20	21	Existing Summer and Winter constraint	7,271
Forecasted								
Waitangirua	16	22	16	Winter	15	16	2017 Winter constraint	6,095

Zone Substation	Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Sustained Peak Demand (MVA)		Date Constraints are Binding And season constrained	ICP Counts as at 2016
		Winter	Summer		2016	2025		
Porirua[38]	20	22	14	Winter	20	24	2019 Summer constraint	5,977
Tawa	16	21	14	Winter	15	17	2023 Winter constraint	5,272
Not Constrained								
Johnsonville	23	21	14	Winter	17	19	Not Constrained	7,142
Kenepuru	23	19	14	Winter	12	12	Not Constrained	2,420

Figure 7-41 Northwestern Area Zone Substation Capacities

The development needs for the Northwestern Area at the subtransmission and distribution level are outlined in the following sections.

7.5.2.1 Subtransmission Development Needs

Subtransmission constraints can be quantified in terms of duration of risk and assessed against the security criteria in Figure 7-1, using a load duration curve. Forecasted constraints are quantified in terms of when the risk is likely to occur based on the forecast peak demand for a given year.

The zone substations that are forecast to be constrained during the planning period are described below.

Ngauranga

The Ngauranga subtransmission circuits from Takapu Rd GXP are repurposed 110kV lines installed on steel pylon towers and owned and maintained by Transpower. A number of factors need to be considered in determining the long term viability of this arrangement.

The sustained peak load supplied at Ngauranga is currently exceeds the cyclic N-1 capacity of the zone substation supply transformers. Post contingency, Ngauranga must be partially off-loaded to avoid overloading the capacity of the remaining transformer. All required switching points are manually operated, thus the restoration time is dependent on the speed of field response. The load at risk is shown in Figure 7-42.

[38] ICP counts for Porirua include Titahi Bay

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
Ngauranga 1	Winter	10	13.5	3.5
	Summer	10	8	-
Ngauranga 2	Winter	10	13.5	3.5
	Summer	10	8	-

Figure 7-42 Ngauranga Z/S Subtransmission Capacity Shortfall

Figure 7-43 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable.

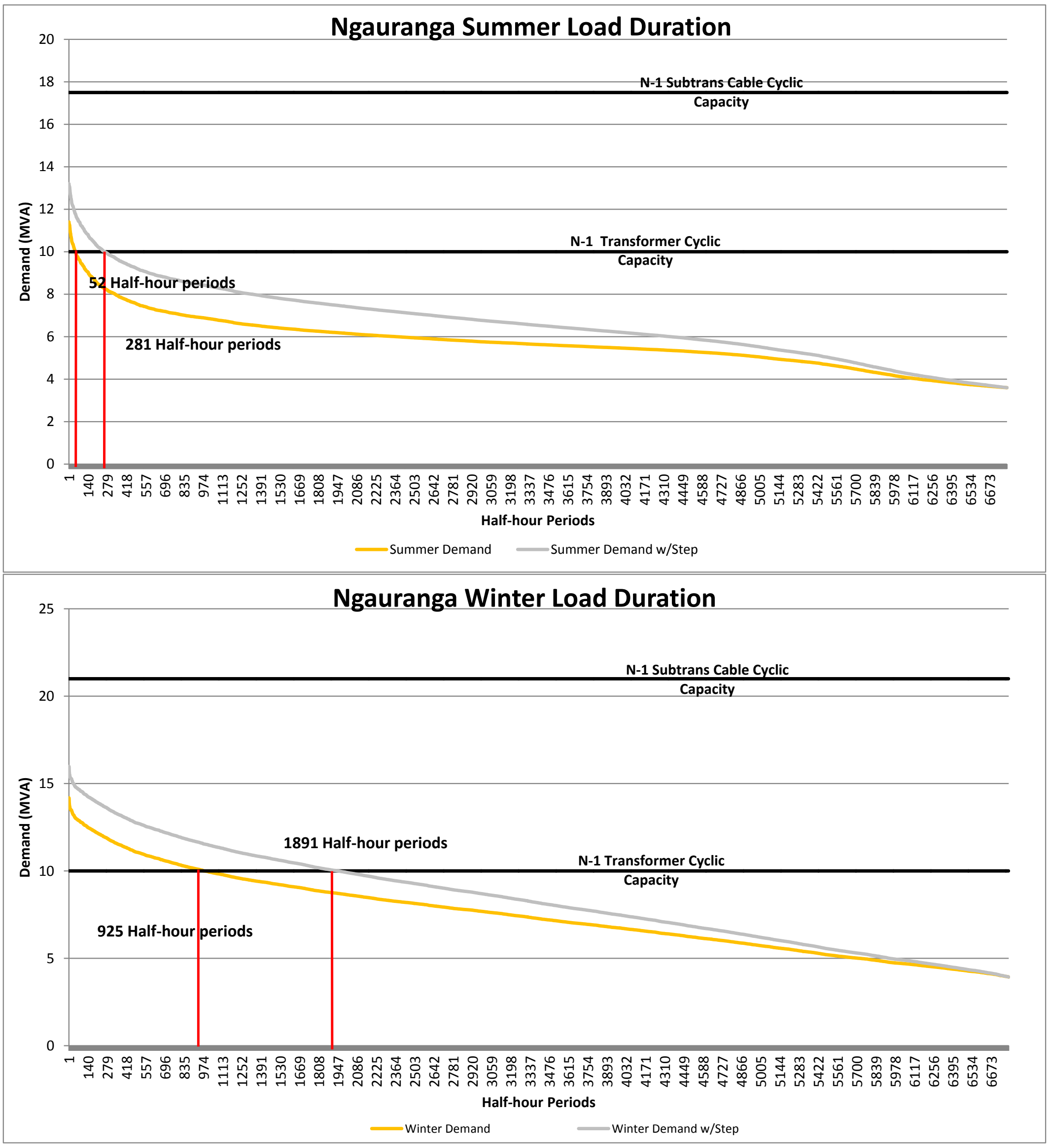


Figure 7-43 Ngauranga Load Duration Curves

The load duration curve shows that a significant proportion of load is at risk. Loading (30 minute average peak demand) during winter exceeds the N-1 transformer cyclic ratings for approximately 5.2% of the time in a year. In the event predicted residential sub-division developments at Grenada proceed as modelled, the duration loading exceeds N-1 capacity during winter increases to 10.7% of the time in a year. Summer peak demand is within the applicable security criteria.

Based on the estimated growth scenarios and development growth within the planning period, the load at Ngauranga can be forecasted for a range of growth and seasonal scenarios as shown in Figure 7-44. The subtransmission capacity constraints are plotted for comparison.

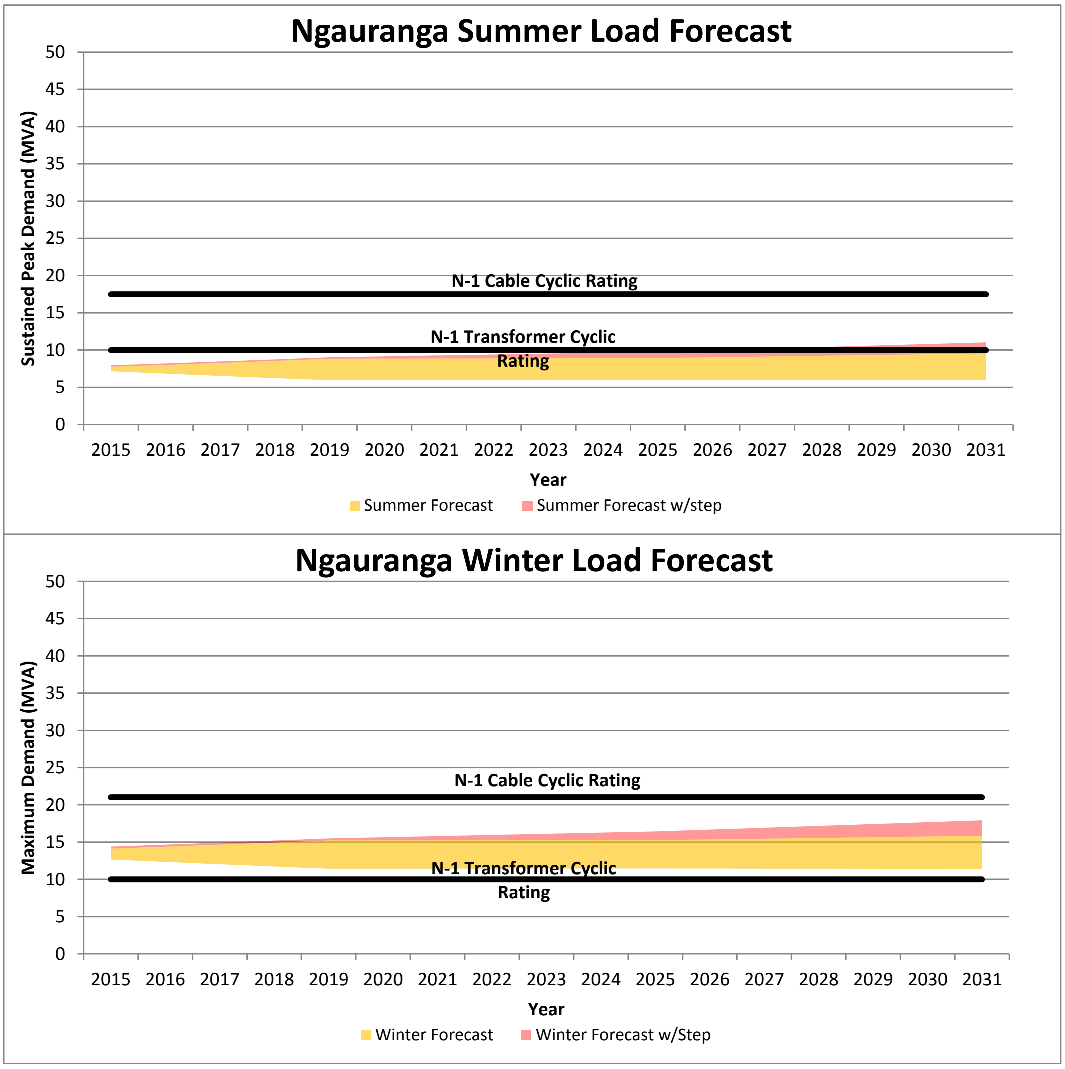


Figure 7-44 Ngauranga Load Duration Forecast

Mana & Plimmerton

There are two constraints at Mana and Plimmerton zone substations. These are:

- The combined load at the two zone substations presently exceed the N-1 rating of the transformers at peak times; and
- 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 and load transfer is required.

The current load at risk at Mana/Plimmerton is shown in Figure 7-45.

Circuit	Constraining N-1 Subtransmission Capacity (MVA)	Sustained Peak Demand (MVA)	Minimum off load for N-1 @ peak (MVA)
Mana-Plimmerton	16	20	3-4

Figure 7-45 Mana-Plimmerton N-1 Capacity

Post contingency of either the Mana or Plimmerton transformers, the load is served via the 11 kV bus tie between the two zone substations. The capacity of the bus tie is lower than the sustained peak demand at Mana. This is illustrated in Figure 7-46.

Circuit	Mana-Plimmerton Bus-tie Capacity (MVA)	Sustained Peak Demand (MVA)	Minimum off load for N-1 @ peak (MVA)
Mana	7	11	3-4
Plimmerton	7	7	-

Figure 7-46 Mana-Plimmerton N-1 Capacity

Figure 7-47 shows the load duration curve against the N-1 cyclic rating of the 11 kV bus-tie.

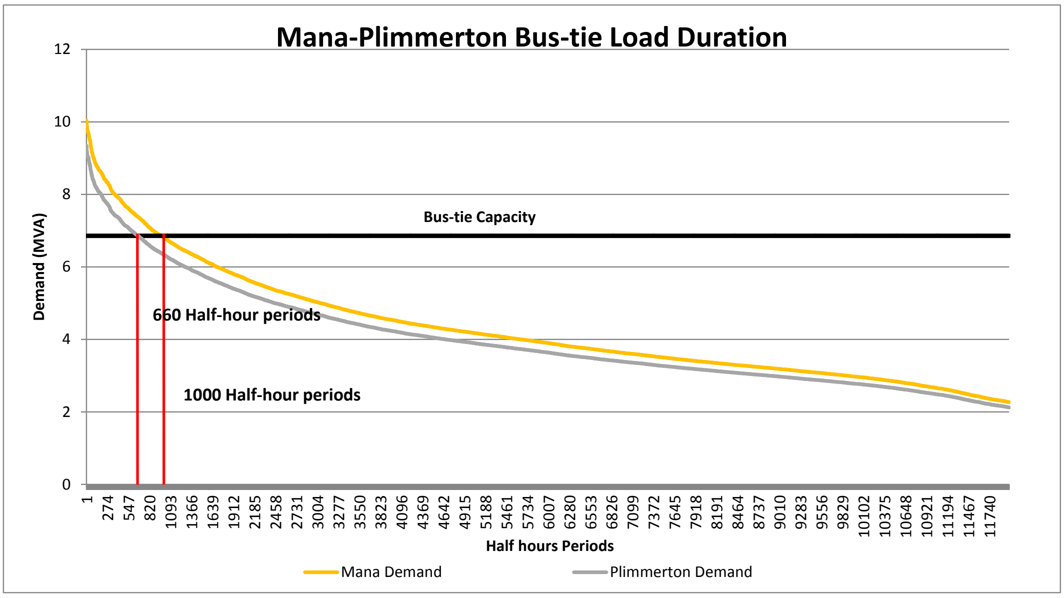


Figure 7-47 Mana-Plimmerton Bus-tie Load Duration Curves

The load duration plot shows that the worst case is an outage of the Mana subtransmission circuit where the peak demand at Mana would exceed the available capacity of the bus-tie for approximately 5.8% of the time in a year.

In the short term, Wellington Electricity can move load between Mana, Plimmerton and Waitangirua, to manage the capacity within ratings.

There is a risk that future step change loading at Mana and Plimmerton will reduce the available transfer capacity and post contingency offload may not be possible.

Figure 7-48 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable.

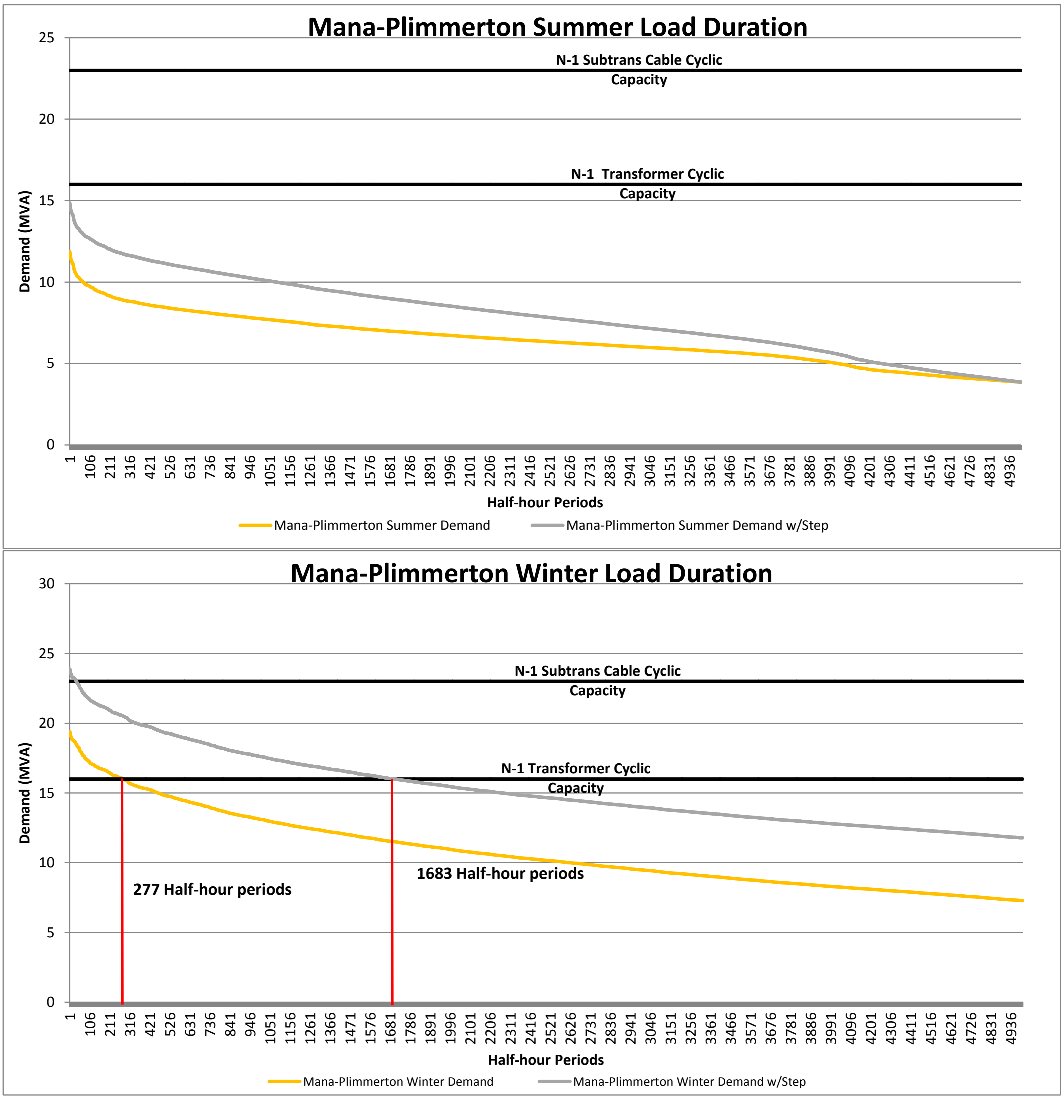


Figure 7-48 Mana-Plimmerton Z/S Load Duration Curves

The load duration curve shows that at present, demand exceeds N-1 subtransmission capacity for approximately 1.5% of the time in a year during winter. While this is currently within acceptable security criteria, step change demand expected within the planning period will increase the duration load is at risk to approximately 9.6% of the time in a year.

Based on the estimated growth scenarios and development growth within the planning period, the load at Mana-Plimmerton can be forecasted for a range of growth and seasonal scenarios as shown in Figure 7-49. The subtransmission capacity constraints are plotted for comparison.

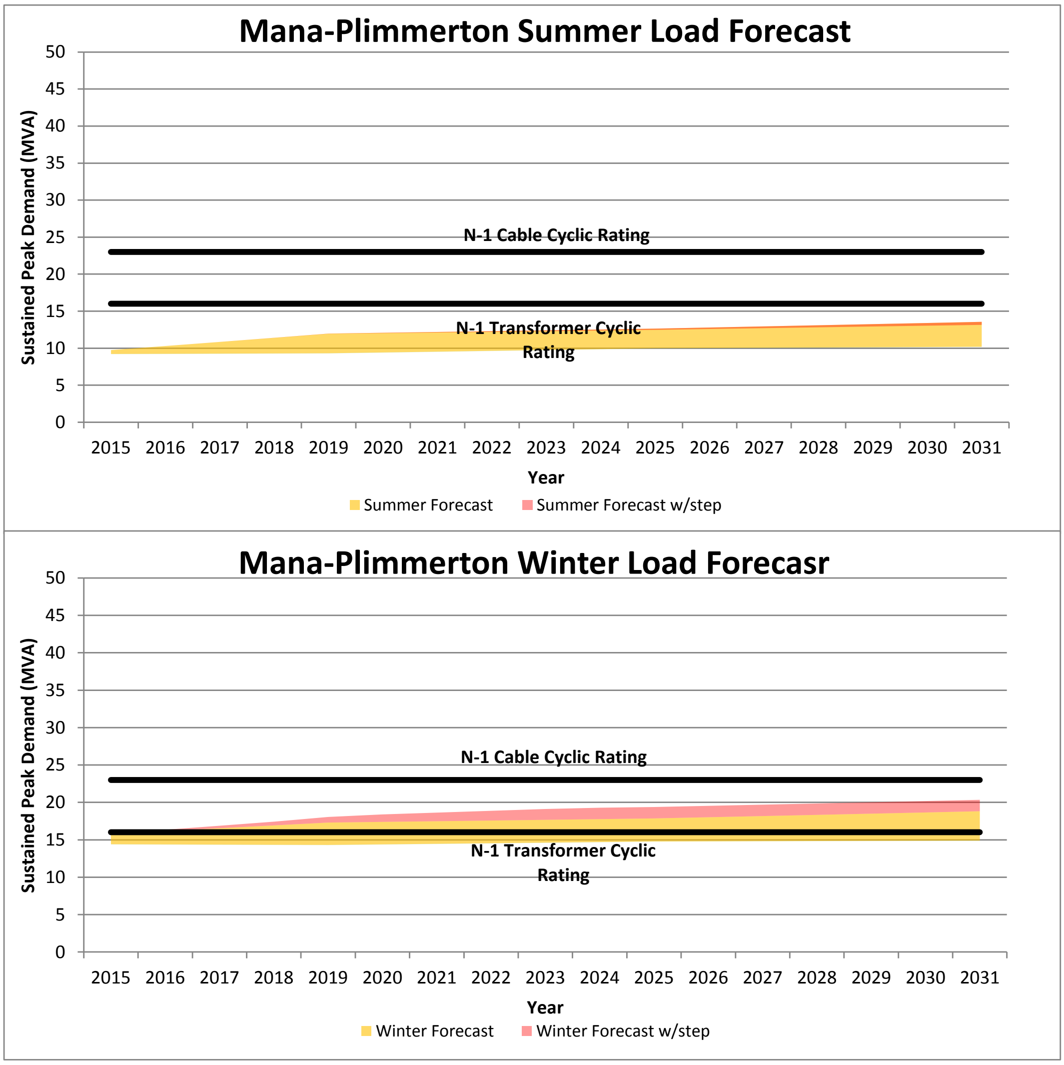


Figure 7-49 Mana-Plimmerton Load Forecast

The load forecast shows that a proportion of load will be at risk by 2019. The magnitude and timing of the risk will be driven by the load growth due to development at residential subdivisions in the Whitby and Aotea areas.

Waitangirua

At present, maximum demand is within available N-1 subtransmission capacity however, step change demand in the short term may result in this constraint being exceeded by 2017.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2017 w/step (MVA)	Minimum off load for N-1 @ peak (MVA)
Waitangirua A	Winter	16	17	1-2MVA
	Summer	16	12	-
Waitangirua B	Winter	16	17	1-2MVA
	Summer	16	12	-

Figure 7-50 Waitangirua Subtransmission Capacity Shortfall

Figure 7-51 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable.

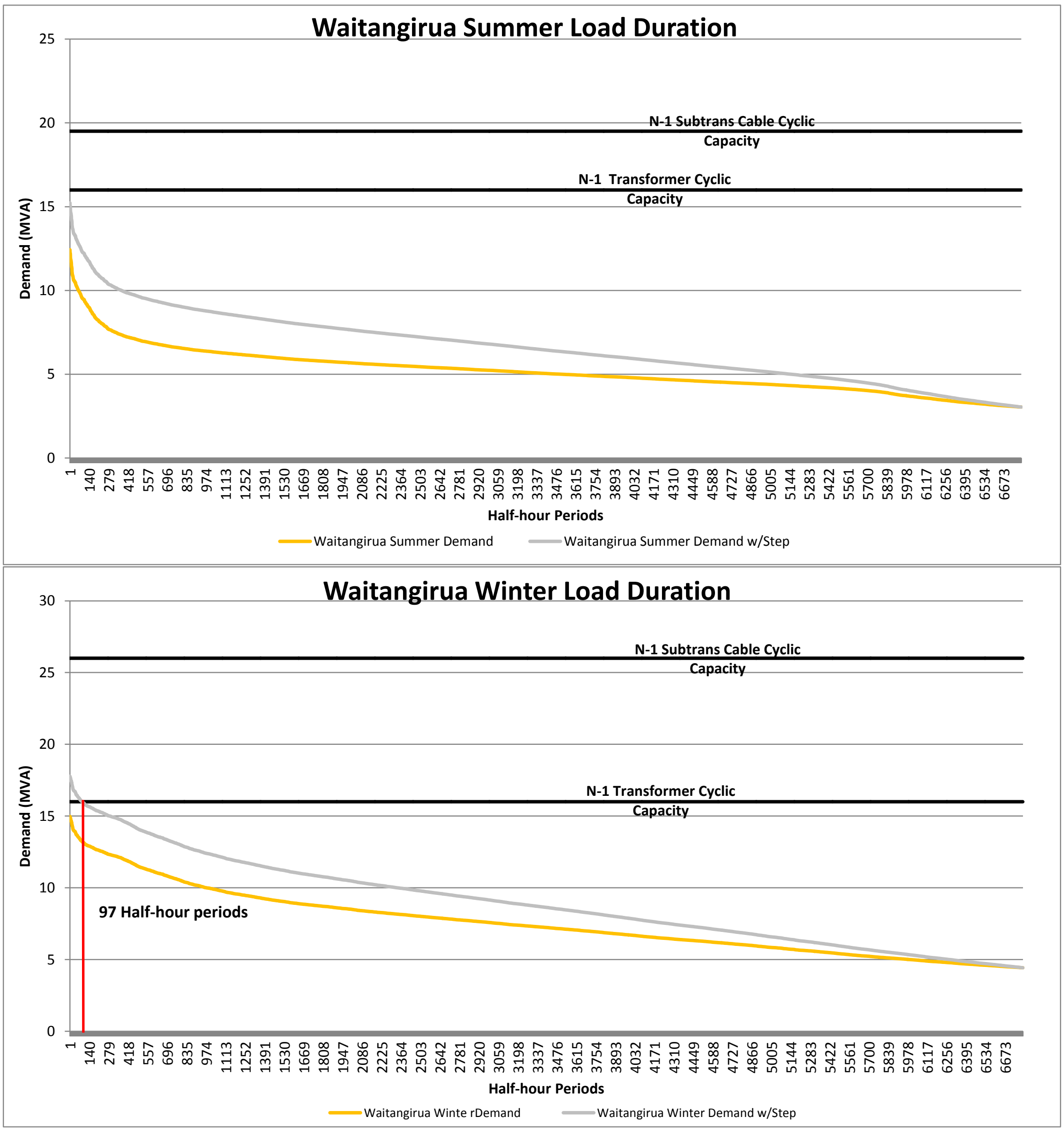


Figure 7-51 Waitangirua Load Duration Curves

The duration that the N-1 subtransmission constraints are exceeded, with the potential step change demand growth, is 0.5% of the time in a year, which is within the security criteria.

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Waitangirua can be forecasted for a range of growth and seasonal scenarios as shown in Figure 7-52.

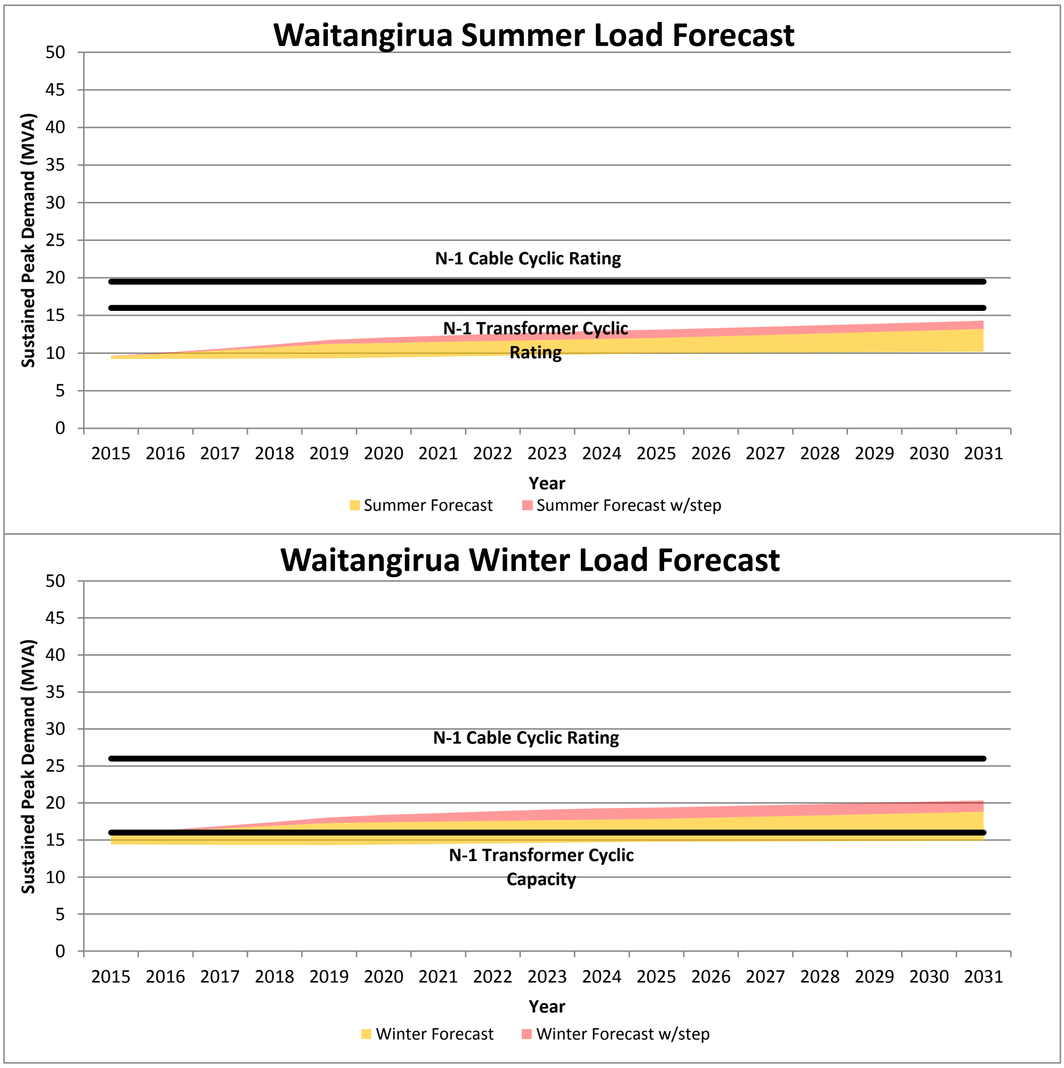


Figure 7-52 Waitangirua Load Forecast

The load forecast also shows that there is a risk that forecasted growth and step change demand during the planning period will exceed the N-1 transformer cyclic ratings by 2017. The magnitude and timing of the breach will be driven by the step change demand due to development at residential subdivisions in Whitby and Aotea.

Porirua

The peak load supplied at Porirua is in breach of summer N-1 ratings and is expected to exceed the winter N-1 capacity of the zone substation supply transformers and subtransmission cables by 2019. The timing is dependent on planned step change demand due to re-development of the Porirua city centre and a number of residential subdivisions in the Whitby and Aotea areas.

Following a fault on the subtransmission system from 2019, load will need to be off-loaded from Porirua to an alternative zone substation.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
Porirua A	Winter	20	20	-
	Summer	17	18	1-2
Porirua B	Winter	20	20	-
	Summer	17	18	1-2

Figure 7-53 Porirua Subtransmission Capacity Shortfall

Subdivisions in the Whitby and Aotea areas will involve commercial centres such as shopping precincts and business premises. Porirua City Council has published plans for re-vitalisation of the Porirua city centre, involving a new plaza, re-development of the Porirua Civic precinct and a number of other initiatives.

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Porirua is forecasted to grow as shown in Figure 7-54.

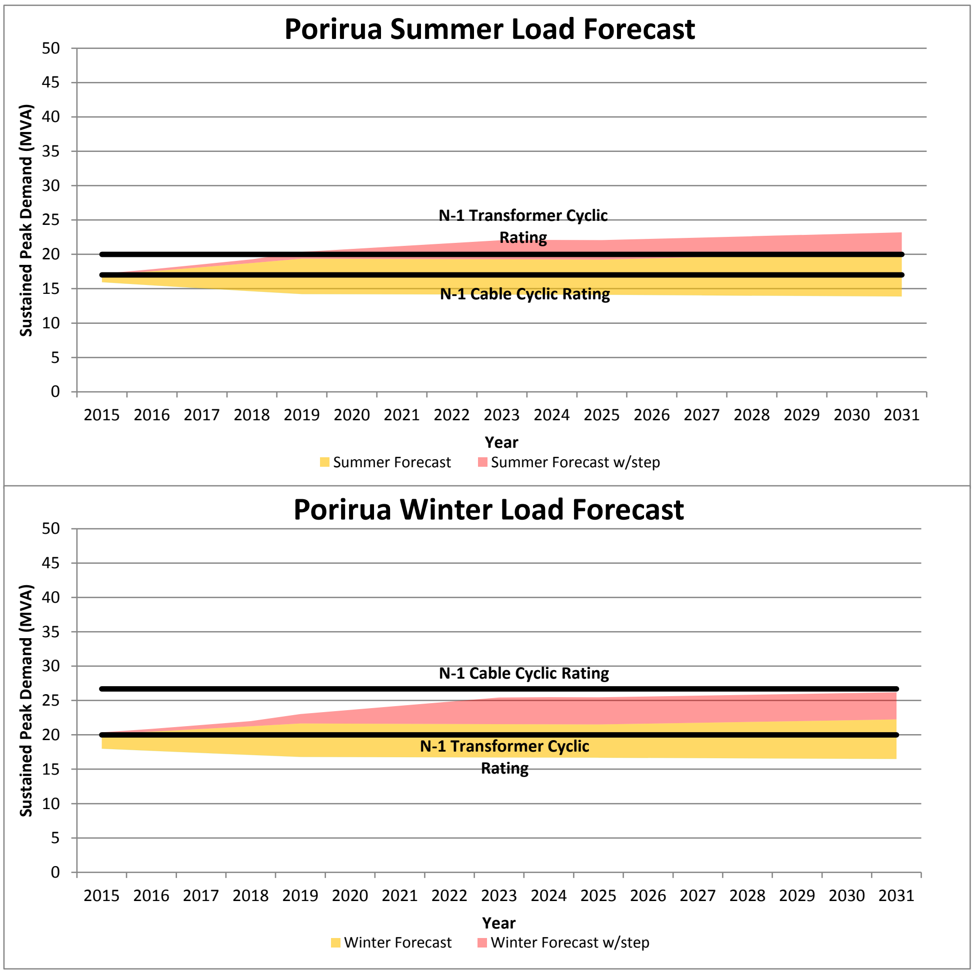


Figure 7-54 Porirua Load Forecast

The shortfall in N-1 capacity could to increase to 7-9MVA by the end of the planning period.

Tawa

At present, maximum demand is within available N-1 subtransmission capacity. It is expected that with growth the sustained peak demand could exceed the N-1 cyclic by 2023.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2023 w/step (MVA)	Minimum off load for N-1 @ peak (MVA)
Tawa A	Winter	16	17	1-2MVA
	Summer	16	14	-
Tawa B	Winter	16	17	1-2MVA
	Summer	16	14	-

Figure 7-55 Tawa Subtransmission Capacity Shortfall

The forecast sustained peak demand at Tawa is shown in Figure 7-56.

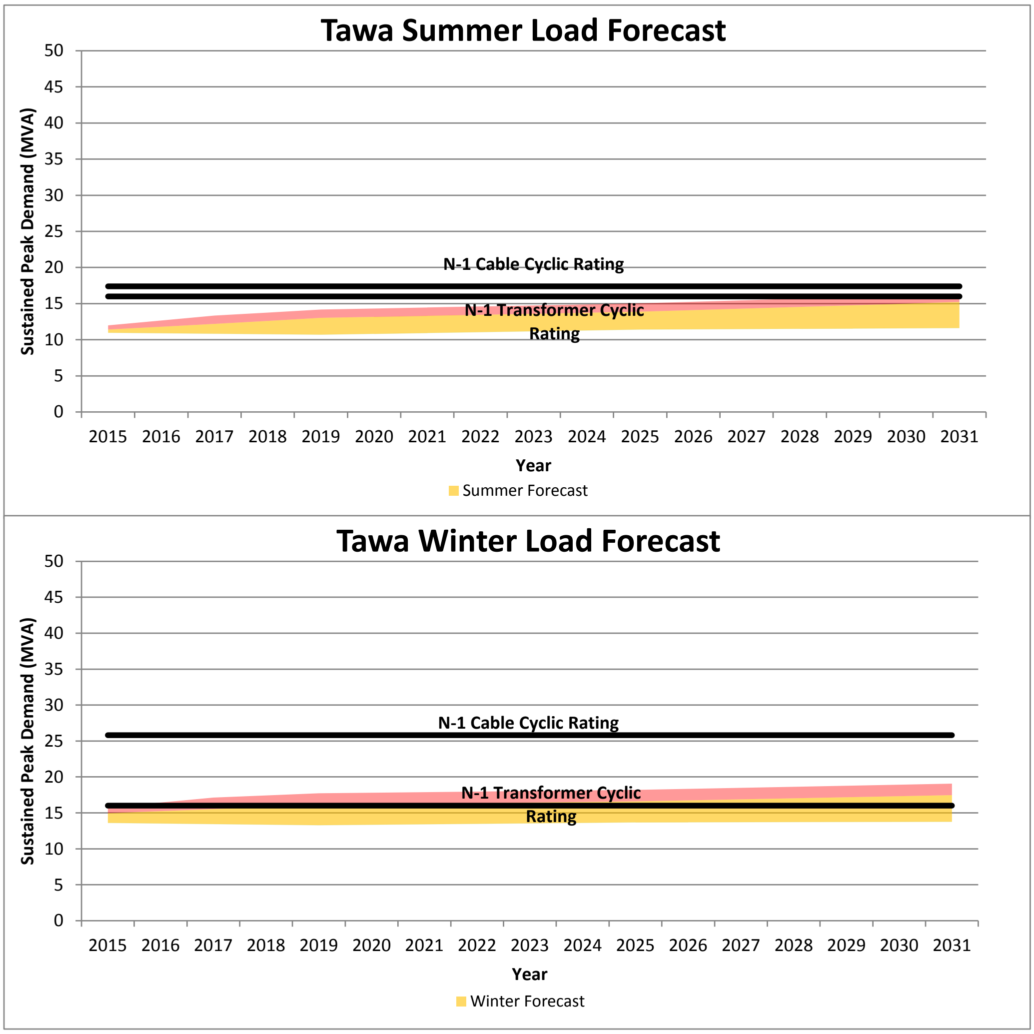


Figure 7-56 Tawa Load Forecast

7.5.2.2 Distribution Level Development Needs

The most critical distribution level issues are those associated with overload of meshed ring feeders supplying a high number of customers or links between zones which can be used for load transfer. Figure 7-57 shows where the applicable security criteria for the feeder configurations are exceeded and an estimation of when the constraints bind.

This is utilised to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder the steady state control that has been applied to manage any risks that might arise has been provided.

Feeder	Topology	Zone Substation	Location of worst case loading	Present	+10 years	Feeder ICP Count	Control
Current							
NGA 01	Radial	Ngauranga	Salford St	68%	73%	1,821	Open point shift
NGA 04[1]	Radial	Ngauranga	16 Malvern Rd	71%	81%	1,644	Open point shift
TAW 10	Radial	Tawa	Duncan St	72%	80%	927	Open point shift
POR 01	2 Fdr Mesh	Porirua	Titahi Bay A	69%	73%	2,921	Monitor growth
POR 11		Porirua	Titahi Bay B	72%	76%		
WTA 05[1]	Radial	Waitangirua	Postgate Dr	75%	89%	1,440	Network augmentation
Within Five Years							
WTA 03[1]	Radial	Waitangirua	Caduceuos Pl		74%	1,409	Network augmentation
TAW 13	Radial	Tawa	Oxford St		71%	1,058	Monitor growth

Figure 7-57 Distribution Level Issues

Notes to Figure 7-57

1: Due to potential step change in the area

Figure 7-58 shows the results of the contingency analysis performed on the meshed ring feeder supplying the Porirua CBD which currently exceeds the security criteria. Overloading feeder segments for each contingency scenario are shown as well as the location of worst case loading. The contingency loading calculation is based on the peak demand for each feeder recorded for 2015.

Meshed Ring	Topology	N-1 Case	Feeder	Worst case loading @	Contingency Loading	Mesh ICP Count	Control
POR 4/5	2 Fdr Mesh	POR 04 out	POR 05	Lyttleton Ave B	106.00%	354	Network augmentation
		POR 05 out	POR 04	7 Titahi Bay Rd	105.00%		

Figure 7-58 Meshed Ring Feeder Contingency Analysis

7.5.3 Northwestern Subtransmission and Distribution Development Options

This section describes the development options available to mitigate the constraints described above.

The development options for the Northwestern Area are comprised of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive and as such there are solutions which meet several needs for the same investment.

The purpose of this section is to describe those development options, establish the overall economic cost of each and identify the optimal staging of investments over the period. As it is impractical to cover all possible combinations of solutions, this section covers four primary development options. Each option has been refined before being presented here to ensure that it is practical. Each result in a different supply risk profile based on the solutions utilised.

7.5.3.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions to defer significant short term investment. These options include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over construction of redundant capacity; and
- Consideration of the cost effectiveness of demand side management to alleviate localised network constraints.

These non-network solutions will be implemented prior to any network investment. Wellington Electricity currently monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets. Where thermal overload limits are at risk of being exceeded, network controllers are able to:

- Initiate shedding of hot water load to provide peak shaving during peak demand periods (in the Northwestern Area, ripple injection is at the zone substation level); and
- Fine tune network open points to optimise feeder loading and feeder customer numbers.

7.5.3.2 Network Investment Options

Common Development Projects

A number of projects will be required to replace assets and improve security of supply. These projects are required irrespective of the development option selected and are as follows:

- Installation of optical fibre links between all zone substations in the Porirua basin to provide protection and SCADA communications while also accommodating future IP connectivity;
- Switching to balance subtransmission loading between Mana and Plimmerton. These works are implemented in lieu of a SPS scheme to limit the load at Mana/Plimmerton to within the capacity of the bus-tie to provide for N-1 security;
- A number of isolated distribution level projects are required in areas to reduce the risk of supply outages to areas with high customer counts or high priority customers; and
- Installation of sectionaliser scheme for Tawa/Kenepuru subtransmission circuits.

Northwestern Area Development Options

The development needs in the Northwestern Area can be separated into two independent areas:

1. North of Tawa, the Porirua Basin and up to Plimmerton. This area is supplied from Porirua, Waitangirua, Mana and Plimmerton zone substations (area referred to as the North below); and
2. The Northwestern suburbs between Ngauranga and Tawa. This area is supplied from Ngauranga, Johnsonville, Tawa and Kenepuru zone substations (area referred to as the South below).

For each area studies have shown that there are two distinct methods for mitigating the issues in each:

a. Augmentation of existing network infrastructure through network upgrades; or

b. Installation of a new zone substation.

Together the combination of these aspects create four development options for the Northwestern Area. The four options are:

1. Augmentation in both the North (1a) and the South (2a): Replacement of subtransmission assets where required, distribution level augmentation to relieve highly loaded feeders;
2. Installation of a new zone substation in the North (1b) and augmentation in the South (2a): Install a new zone substation in the Pauatahanui area; replace the Ngauranga transformers and shift open points in Johnsonville, Ngauranga and Tawa to relieve highly loaded feeders;
3. Augmentation in the North (1a) and install an new zone substation in the South (2b): Replace the Mana and Plimmerton transformers and install new distribution infrastructure to relieve highly loaded feeders and optimise loading between Porirua, Waitangirua, Mana and Plimmerton; install a new zone substation in the Grenada area,; and

4. Installation of a new zone substation in the North (1b) and install a new zone substation in the South (2b): Install two new zone substations, one in the Grenada area and one in Pauatahanui. Optimise loading by shifting open points.

There are a number of benefits that each option offers, which need to be considered against the cost of each option. For example, the installation of a new zone substation at Pauatahanui provides the opportunity to mitigate the identified transmission constraints due to the capacity and age of the supply transformers by either:

- Upgrading the capacity of the Pauatahanui 110/33kV transformers to provide capacity to the Pauatahanui zone substation;
- Replacing the existing Pauatahanui 110/33kV transformers with three-winding units and supplying a new Pauatahanui zone substation at 11kV; or
- Installing two new 110/11kV transformers at Pauatahanui to supply a new Pauatahanui zone substation.

Options involving a new zone substation in Grenada (Options 3 and 4) provide the opportunity to potentially decommission the Ngauranga zone substation. All supplied load from Ngauranga could be transferred to the new Grenada zone substation and Johnsonville, such that Ngauranga could be decommissioned.

The benefits and the costs of each option are described in more detail below.

Option 1: Augmentation in both the North (1a) and the South (2a)

This option involves augmentation of the subtransmission and distribution networks in both the north and south areas to alleviate the identified issues.

A number of open point changes are made to optimise loading in the network. The distribution augmentation projects are then implemented to overlay undersized cable segments and improve feeder capacity at Ngauranga, reinforce the distribution ring supplying the Porirua city centre and improve the inter-connectivity and capacity of the Waitangirua distribution network. A number of smaller projects are enacted around these works to alleviate localised distribution level constraints, replace aging assets and improve security of supply.

The demand at Pauatahanui GXP is constrained by the capacity of the 110/33kV transformers. Wellington Electricity would need to initiate a project with Transpower to replace these transformers with higher rated units as part of this option.

Figure 7-59 provides a visual representation describing the final network configuration from development path.

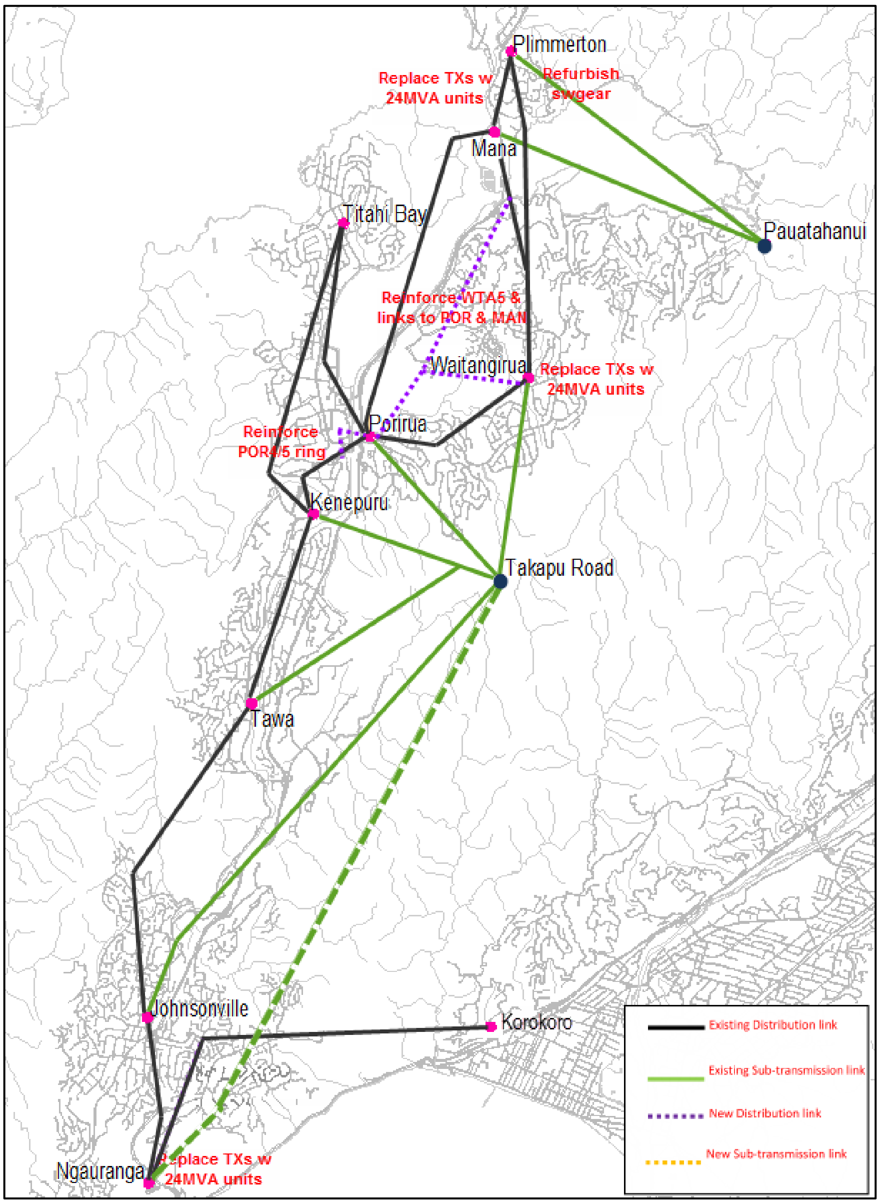


Figure 7-59 Network Configuration – Option 1

The estimated cost of this network development option is shown in Figure 7-60.

Project Description	Cost ($M)
Total marginal cost of network reinforcement	11.4
Common Projects for all options (fibre links + common cable reinforcements)	3.4
Total NW Area NDRP Investment - Option 1	**14.8**
Additional condition-based asset renewal projects required under Option 1	5.7
Total cost of Option 1	**20.5**
Comparative NPV (total cost less common projects plus renewal expenditure)	12.4

Figure 7-60 Estimated Cost of Network Development Option 1

The benefits of this option are:

- Replaces assets nearing end of life, or posing a risk to network resilience;
- Increases capacity into high growth areas and zones with existing capacity constraints; and
- Projects can be separated into many discreet elements and scheduled to provide a more uniform investment profile.

The risks associated with this option are:

- Does not cater for long term growth outside of planning period or growth in excess of forecast; and
- Capacity based asset replacement at some sites where asset condition is generally good, but assets are highly utilised.

Option 2: Installation of a New Zone Substation in the North (1b) and Augmentation in the South (2a)

This option involves establishment of a new zone substation in the Pauatahanui/Whitby area, supplied from Pauatahanui GXP, to provide capacity for future growth in this area and relieve the loading at Waitangirua, Porirua, Mana and Plimmerton. The new zone substation would have distribution feeders inter-connecting with a number of highly loaded feeders within the Porirua basin.

There are three potential sub-options to provide subtransmission supply to this new zone substation:

- Installation of new 33kV cabling from Takapu Road. These cables would be terminated directly to two new 33/11kV 24MVA transformers. These transformers will feed the Pauatahanui zone substation bus. These works could be a customer initiated project with Transpower and funded through increased connection charges;
- Installation of two new bays on the 110kV bus at Pauatahanui GXP. The new 110kV bays would supply two new 110/11kV 24MVA transformers, with an estimated cost of $3 million. These works would be a customer initiated project with Transpower and funded through increased connection charges; or
- Replacement of the existing Pauatahanui 110/33kV transformers with two new 110/33/11kV transformers with capacity of at least 50MVA. These transformers would supply both the 33kV bus at Pauatahanui and the 11kV bus at the new Pauatahanui zone substation. These works would be a customer initiated project with Transpower and funded through increased connection charges.

The recommended sub-option is to initiate a project with Transpower to replace the existing 110/33kV transformers at Pauatahanui with two new 110/33/11kV units.

A number of distribution level works will be enacted to overlay undersized cable segments and improve feeder capacity of Ngauranga, where feeders are connected to the Grenada area, as well as to reinforce the distribution ring supplying the Porirua city centre. Installation of a new zone substation in the Pauatahanui/Whitby area allows for reduction of utilisation at Mana and Plimmerton, potentially negating replacement of the transformers at these stations. Upgrade of the transformers at Ngauranga will be required.

The Figure 7-61 provides a visual representation describing the final network configuration from the development path.

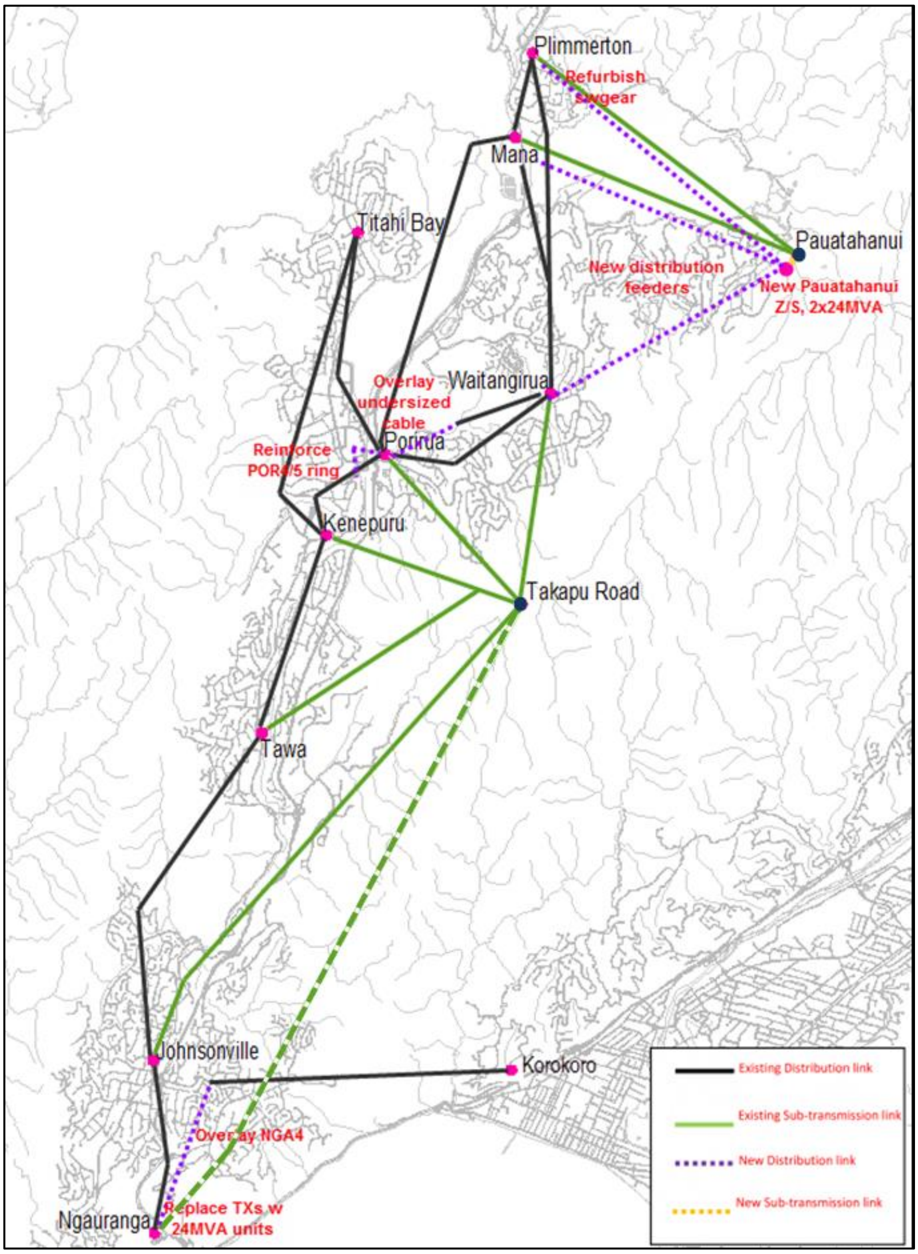


Figure 7-61 Network Configuration – Option 2

The benefits of this option are:

- Introduces a new connection point from an independent GXP into the high growth areas in Porirua, Waitangirua, Mana and Plimmerton;
- Alleviates capacity constraints at Waitangirua, Porirua, Mana and Plimmerton.
- Relieves loading constraints due to the capacity of the Pauatahanui GXP 110/33kV transformers;
- Targeted distribution augmentation projects alleviate issues within the Ngauranga 11kV network; and
- Defers age based replacement of assets by reducing utilisation and criticality.

The risks associated with this option are:

- Requires significant investment to establish a new zone substation; and
- The investment profile during the planning period is not uniform, and is instead clustered around two years of investment required for each zone substation project.

The estimated cost of this network development option is shown in Figure 7-62.

Project Description	Cost ($M)
New Pauatahanui Zone Substation & additional network reinforcement	10.9
Common Projects for all options (fibre links + common cable reinforcements)	3.4
Total NW Area NDRP Investment - Option 2	**14.3**
Additional condition-based asset renewal projects required under Option 2*	3.0
Total Cost of Option 2	**17.3**
Comparative NPV (total cost less common projects plus renewal expenditure)	11.4

Figure 7-62 Estimated cost of Network Development Option 2

*Note: The asset renewal expenditure under Options 2 and 4, used in the NPV analysis is $3 million. This is lower than accounted for in Options 1 and 3 ($5.7 million), as it reduces the criticality of a number of assets in the North, allowing capital expenditure deferral.

Option 3: Grenada Zone Substation and Whitby/Aotea Network Augmentation

This option includes installation of a new zone substation at Grenada. This station will be supplied from Takapu Road GXP and established on a section of land in Grenada North, which has been pre-designated for construction of a new zone substation. This zone substation will have feeders interconnecting with highly loaded feeders from Ngauranga, Johnsonville and Tawa.

A number of distribution level works will be implemented to overlay undersized cable segments and improve feeder capacity at Ngauranga as well as to reinforce the distribution ring supplying the Porirua city centre. Transformer replacement will be required Mana and Plimmerton by 2020 and Waitangirua by 2021.

To provide subtransmission supply to a new Grenada zone substation, the three options available are:

- Installation of a 33kV bus to provide a tee-ed supply to the new zone substation via from the TKR-NGA subtransmission circuits. This tee-off will supply 2x24MVA transformers at the Grenada zone substation. The incremental cost of these works is expected to be $4.4 million;
- Directly tee-off the TKR-NGA subtransmission circuits via fused disconnects or solid links, similar to the Tawa/Kenepuru tee-off. This tee-off will supply 2x24MVA transformers at the Grenada zone substation. The incremental cost of these works is expected to be $3.4 million; or
- Install new subtransmission cabling from Takapu Road. These new cables will supply two new 24MVA transformers at the Grenada zone substation. The incremental cost of these works is expected to be $5.4 million.

The recommended option is to install a 33kV bus to provide a tee-off to the new Grenada zone substation from the TKR-NGA subtransmission circuits.

The demand at Pauatahanui GXP is constrained by the capacity of the 110/33kV transformers. Wellington Electricity will need to initiate a project with Transpower to replace these transformers higher rated units within as part of this option.

Installation of a new zone substation in the Grenada area allows reduction in Ngauranga zone substation load to either reduce the utilisation of the Ngauranga transformers or to allow eventual decommissioning.

The Figure 7-63 provides a visual representation describing the final network configuration from the development path.

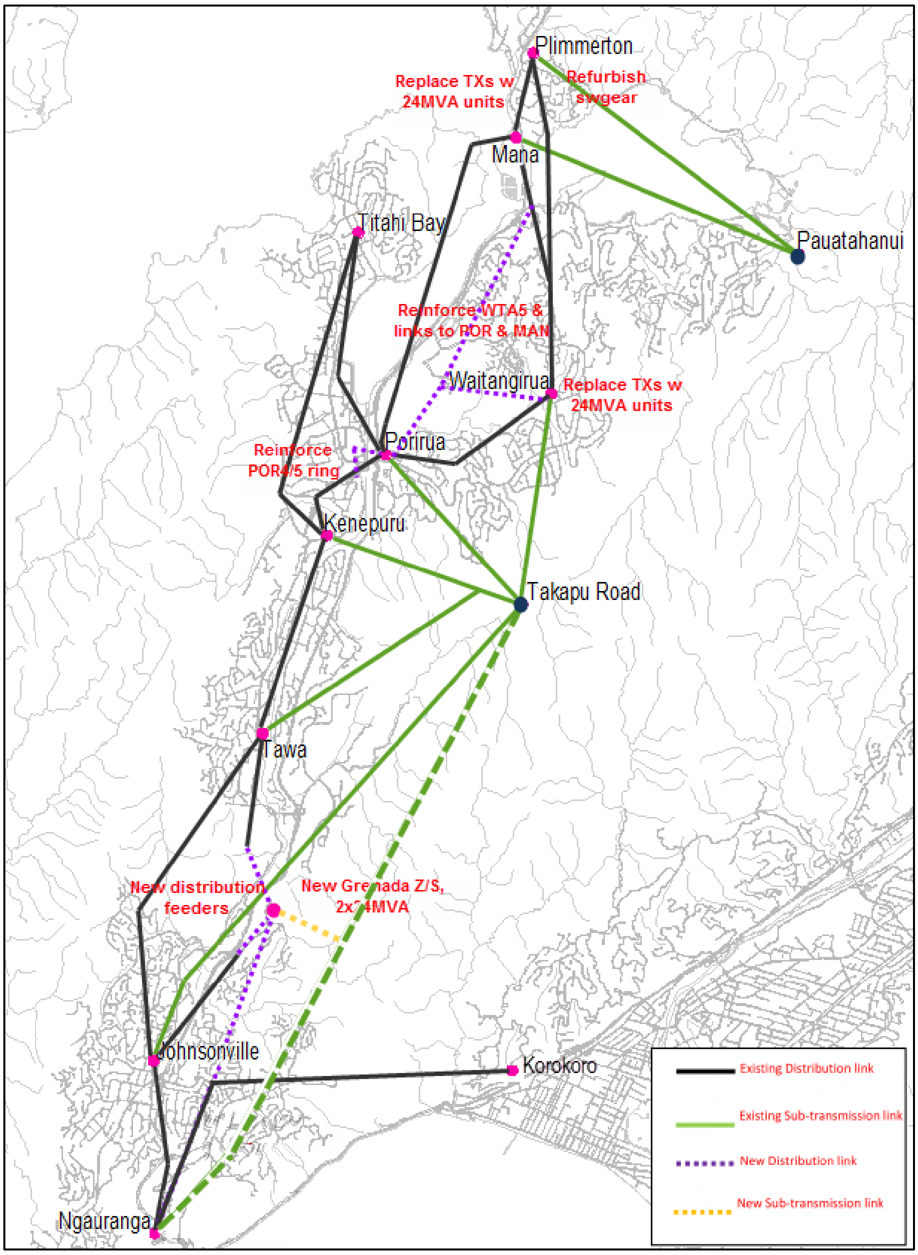


Figure 7-63 Network Configuration – Option 3

The benefits of this option are:

- Introduces a new connection point into the high growth areas in Grenada;
- Alleviates capacity constraints at Ngauranga due to Grenada residential developments;
- Targeted distribution augmentation projects to alleviate issues within Waitangirua, Porirua, Mana and Plimmerton 11kV networks; and
- Offers the opportunity to decommission Ngauranga zone substation, avoiding costly asset renewal at this site.

The risks associated with this option are:

- Requires significant investment to establish a new zone substation
- The investment profile during the planning period is not uniform, and is instead clustered around two years of investment required for each zone substation project; and
- Significant distribution augmentation and asset replacement is still required at Waitangirua, Porirua, Mana and Plimmerton.

The estimated cost of this network development option is shown in Figure 7-64.

Project Description	Cost ($M)
New Grenada Zone Substation & additional network reinforcement	21.6
Common Projects for all options (fibre links + common cable reinforcements)	3.4
Total NW Area NDRP Investment - Option 3	**25.0**
Additional condition-based asset renewal projects required under Option 3	5.7
Total cost of Option 3	30.7
Comparative NPV (total cost less common projects plus renewal expenditure)	17.1

Figure 7-64 Estimated Cost of Network Development Option 3

Option 4: Pauatahanui Zone Substation and Grenada Zone Substation

This option involves installation of two new zone substations, one in Grenada and the other in the Pauatahanui/Whitby area. These new stations provide for the expected growth in the Porirua basin as well as relieving all current constraints.

The new zone substation at Pauatahanui will defer replacement of the transformers at Waitangirua, Mana and Plimmerton outside of the planning period while the new zone substation at Grenada offers the opportunity to partially or completely offload the Ngauranga zone substation. Replacement of the Ngauranga transformers will be driven by condition and may be deferred till the end of the planning period.

A number of smaller projects are enacted around these works to alleviate localised distribution level constraints, replace aging assets and improve security of supply.

Figure 7-65 provides a visual representation describing the final network configuration from the development path.

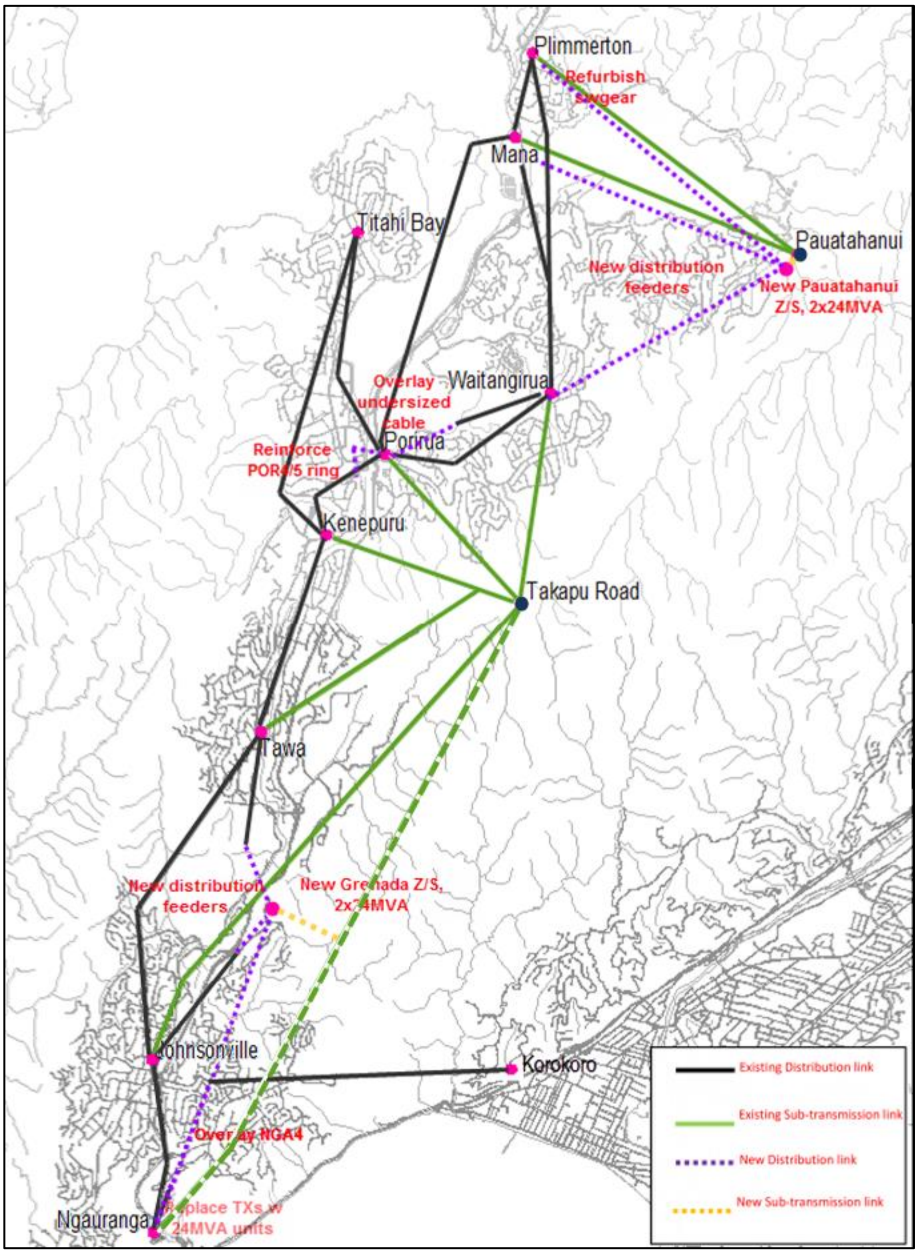


Figure 7-65 Network Configuration – Option 4

The benefits of this option are:

- Introduces new connection points into the high growth areas in Grenada, Porirua, Waitangirua, Mana and Plimmerton;
- Relieves loading constraints due to the capacity of the Pauatahanui GXP 110/33kV transformers;
- Defers age based replacement of assets at Ngauranga, Waitangirua, Mana and Plimmerton by reducing utilisation and criticality; and
- Caters for long term network growth in the Northwestern area.

The risks associated with this option are:

- Requires significant investment to establish two new zone substations; and

- The investment profile during the planning period is not uniform, and is instead clustered around two years of investment required for each zone substation project.

The estimated cost of this network development option is shown in Figure 7-66.

Project Description	Cost ($M)
New Pauatahanui Zone Substation	7.2
New Grenada Zone Substation & additional network reinforcement	12.5
Common Projects for all options (fibre links + common cable reinforcements)	3.4
Total NW Area NDRP Investment - Option 4	**23.1**
Additional condition-based asset renewal projects required under Option 4	3.0
Total cost of Option 4	26.1
Comparative NPV (total cost less common projects plus renewal expenditure)	15.5

Figure 7-66 Estimated Cost of Network Development Option 4

7.5.4 The Northwestern Area Development Plan

The most cost effective solution which mitigates all identified issues while also ensuring optimised network capacity and security of supply is Option 2: Installation of a new zone substation in the North (1b) and augmentation in the South (2a).

Option 2 involves the following discrete milestones and timing of works to mitigate the identified constraints in the most feasible and cost-effective manner:

- **2016/17** – Open point shifts will be enacted to alleviate a number of distribution constraints at Tawa, Porirua and Ngauranga;

- **2018** – Reinforce Porirua CBD ring by increasing meshing. A new cable will be installed between 17 Parumoana Street and 14 Parumoana Street. This project will be initiated by any customer connections which result in the planning criteria of the Porirua CBD ring being exceeded;

- **2020** – Install a new feeder from Porirua zone substation to reinforce the Porirua CBD ring and provide additional supply security and capacity for projected growth due to the Porirua city centre revitalisation initiative;

- **2020** – Replace the transformers at Ngauranga with higher capacity units. The existing transformers are at an advanced age and constrain capacity for growth in the Johnsonville, Newlands, Woodridge and Grenada areas;

- **2020/21** – Install a new zone substation to supply load in the Whitby and Aotea areas. This new zone substation would consist of a new 11kV bus in the vacant land adjacent to the Pauatahanui GXP. The existing Pauatahanui 110/33kV transformers are at an advanced age and constrain capacity for growth. A customer project will be initiated to replace these units with new 110/33/11kV transformers providing at least 50MVA of N-1 capacity; and

- **2022/23** – Open point shifts will be enacted to alleviate a distribution constraint within the Plimmerton distribution network.

The majority of identified feeder overloads will be eliminated by the end of the planning period. Construction of a new zone substation in Grenada, as indicated in previous AMPs, has been deferred in lieu of increasing subtransmission and distribution capacity at Ngauranga by replacing the Ngauranga transformers and reinforcing the distribution network.

7.5.5 Summary of the Northwestern Area Investment

Figure 7-67 shows the investment plan for growth and reinforcement projects in the Northwestern area for the planning period from 2016-2026. All subtransmission protection relay and RTU replacement projects are categorised as asset renewal expenditure, detailed in Section 6. Further detail of each project is provided in Appendix C.

Year	Project	Estimated Cost	Comments
2016	Takapu Road Communications - Stage 1	0.4	Common Project
2017	Takapu Road Communications - Stage 2	0.9	Common Project
	Tawa/Kenepuru Sectionaliser Scheme	0.3	Common Project
	Allowance for minor cable reinforcement works	0.2	Common Project
2018	Reinforce the Porirua CBD Ring - Stage 1	0.3	Common Project
	Allowance for minor cable reinforcement works	0.4	Common Project
2020	New Pauatahanui Zone Substation	2.5	NDP Option 2
	Reinforce the Porirua CBD Ring - Stage 2	0.9	Common Project
	Replace the Ngauranga Transformers	3.0	NDP Option 2
2021	New Zone Substation distribution links to Waitangirua and Mana/Plimmerton – Stage 1	2.0	NDP Option 2
2022	New Zone Substation distribution links to Waitangirua and Mana/Plimmerton – Stage 2	2.7	NDP Option 2
	Allowance for minor cable reinforcement works	0.5	NDP Option 2
2023	Allowance for minor cable reinforcement works	0.2	NDP Option 2
	Total Investment	**14.3**	

Figure 7-67 Summary of Northwestern Area Growth Investment Requirement ($M in constant prices)

7.6 Northeastern Area NDRP

The Hutt Valley (photography credit: Hutt City Council)

This section provides a summary of the Northeastern Area NDRP. This section is structured as follows:

- Identified GXP development needs;
- Identified subtransmission and distribution level development needs and options;
- The network development plan for the planning period; and
- A summary of the expected expenditure profile.

7.6.1 GXP Development

The Northeastern area is supplied from four GXPs. Gracefield and Upper Hutt provide subtransmission supply at 33kV while Melling and Haywards GXPs provide subtransmission supply at 33kV and 11kV. The transformer capacity and the maximum system demand are set out in Figure 7-68.

GXP	Installed Capacity (MVA)	Firm Capacity (MVA)	Sustained System Maximum Demand MVA	
			2016	2026
Gracefield 33kV	2x100	89[1]	64	63
Haywards 33kV	1x20	20	15	15
Melling 33kV	2x50	52	34	34
Upper Hutt 33kV	2x40	37[1]	30	33
Haywards 11kV	1x20	20	19	19

GXP	Installed Capacity (MVA)	Firm Capacity (MVA)	Sustained System Maximum Demand MVA	
			2016	2026
Melling 11kV	2x25	30	27	28

Figure 7-68 Northeastern Area GXP Capacities

1: Transformer capacity constrained by protection constraint

Gracefield

Currently there are two transformers at Gracefield, which provide 33kV supply to four Wellington Electricity zone substations (Wainuiomata, Gracefield, Seaview and Korokoro). There are no capacity and security constraints at Gracefield as the sustained peak demand at this GXP is below the N-1 supply transformer capacity.

Haywards

Haywards supplies Trentham zone substation via a 33kV outdoor bus and an 11kV switchboard, which is fed by a 20MVA 110/11kV transformer in parallel with a 5MVA 33/11kV transformer. The loss of either of the 110/33kV or 110/11kV supply transformers has a significant impact on system security.

Transpower has identified the need to replace the existing transformers at Haywards due to their condition, with an indicative timing of 2017-2019. Outages required for routine maintenance and similar activities require back-feed switching at the distribution level due to the atypical configuration of the supply to the Haywards 33kV and 11kV buses.

Transpower have indicated that the preferred solution is to install two three winding transformers with sufficient capacity to provide N-1 security for both 11kV and 33kV supplies. The final configuration, as well as the ratings of the new transformers and the timing of the project, has yet to be confirmed and may influence network development options for the Wellington Northeastern area.

Transpower have also indicated plans to replace the 33kV outdoor bus at Haywards GXP with a new indoor GIS switchboard by 2017-2020. A provisional sum has been allowed for in the Northeastern area investment plan to account for any design, switching, installation or commissioning works required of Wellington Electricity to facilitate this project.

Upper Hutt

The Upper Hutt GXP comprises two parallel 110/33kV transformers nominally rated at 37 MVA each, supplying a 33kV bus that feeds zone substations at Brown Owl and Maidstone through underground 33kV fluid-filled cables.

Transpower has indicated that the existing Upper Hutt GXP 33kV outdoor bus is to be replaced by an indoor switchboard in 2020. During this outdoor to indoor conversion, Wellington Electricity will look to upgrade all subtransmission differential protection on the Brown Owl and Maidstone circuits. A provisional sum has been allowed for in the Northeastern area investment plan to account for any design, switching, installation or commissioning works required of Wellington Electricity to facilitate this project.

Melling

The Melling GXP comprises a conventional arrangement of two parallel 110/33kV transformers nominally rated at 50 MVA each, supplying a 33kV switchboard that feeds the zone substations of Waterloo and Naenae. A separate 11kV switchboard is supplied by a parallel arrangement of two 110/11kV transformers nominally rated at 30MVA each.

The capacity of the 110/11kV transformers is restricted due to the limit imposed by the protection scheme. Transpower propose to resolve this protection limitation to increase the cyclic capacity of the transformers.

Wellington Electricity's own demand forecast shows that the cyclic capacity of the transformers is sufficient for the level of growth anticipated during the planning period. However, the increased capacity from the resolution of the protection imposed capacity limit will allow greater flexibility for post-contingency operation.

7.6.2 Subtransmission and Distribution Development Plans

This section describes the identified security of supply constraints and development needs for the Northeastern Area subtransmission and distribution networks.

7.6.2.1 Subtransmission Development Needs

The Wellington Northeastern network consists of nine subtransmission 33kV circuits supplying nine zone substations. Each zone substation supplies the respective 11kV distribution network with inter-connectivity via switched open points to adjacent zones. The Haywards and Melling GXP 11kV switchboards directly feed into the distribution network. The characteristics of each zone substation are listed in Figure 7-69.

Zone Substation	Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Forecast Sustained Peak Demand (MVA)		Date Constraints are Binding And season constrained	ICP Counts as at 2016
		Winter	Summer		2016	2026		
Existing								
Korokoro [1]	23	18.2	12.6	Winter	19	22	Existing Summer and Winter constraint	6,929[2]
Forecasted								
Waterloo	23	23.7	14.3	Winter	16	16	2017 Summer constraint	5,782
Maidstone [3]	22	20.7	13.2	Winter	15	15	2024 Summer constraint	4,365
Not Constrained								
Brown Owl	23	22.3	15.9	Winter	15	16	Not Constrained	6,332

Gracefield	23	20.2	15.2	Winter	11	10	Not Constrained	2,610
Wainuiomata[4]	20	21	14.2	Winter	16	16	Not Constrained	6,676
Trentham	23	23.9	17.7	Winter	15	15	Not Constrained	5,125
Seaview	22	18	13.5	Winter	15	15	Not Constrained	2,846
Naenae	23	22	18	Winter	15	15	Not Constrained	6,042

Figure 7-69 Northeastern Area Zone Substation Capacities

Notes to Figure 7-69

1: The capacity of the Korokoro subtransmission cables is currently being investigated.

2: The total number of ICPs supplied from Korokoro zone substation also includes those previously supplied from Petone.

3: The capacity of the Maidstone subtransmission cables is currently being investigated.

4: The N-1 capacity at Wainuiomata zone substation is constrained by the rating of the relocated 20MVA transformer from Petone

Korokoro

The peak load supplied at Korokoro currently exceeds the N-1 cyclic capacity of the subtransmission cables as shown in Figure 7-70.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Peak Demand @ 2015 (MVA)	Minimum off load for N-1 @ peak (MVA)
Korokoro 1	Winter	16.6	19	3
	Summer	12.6	12	-
Korokoro 2	Winter	16.6	19	3
	Summer	12.6	12	-

Figure 7-70 Korokoro Subtransmission Capacity Shortfall

The peak demand at Korokoro is expected to increase to 22MVA, increasing the capacity shortfall to approximately 5MVA. Following a fault on the subtransmission system, Wellington Electricity restores supply to consumers through partially off-loading Korokoro to an alternative zone substation. Available distribution level transfer capacity is sufficient at all times to back-feed sufficient load to avoid overloading the remaining transformer. However, all required switching points are manually operated, thus the restoration time will be dependent on the speed of field response.

Figure 7-71 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable.

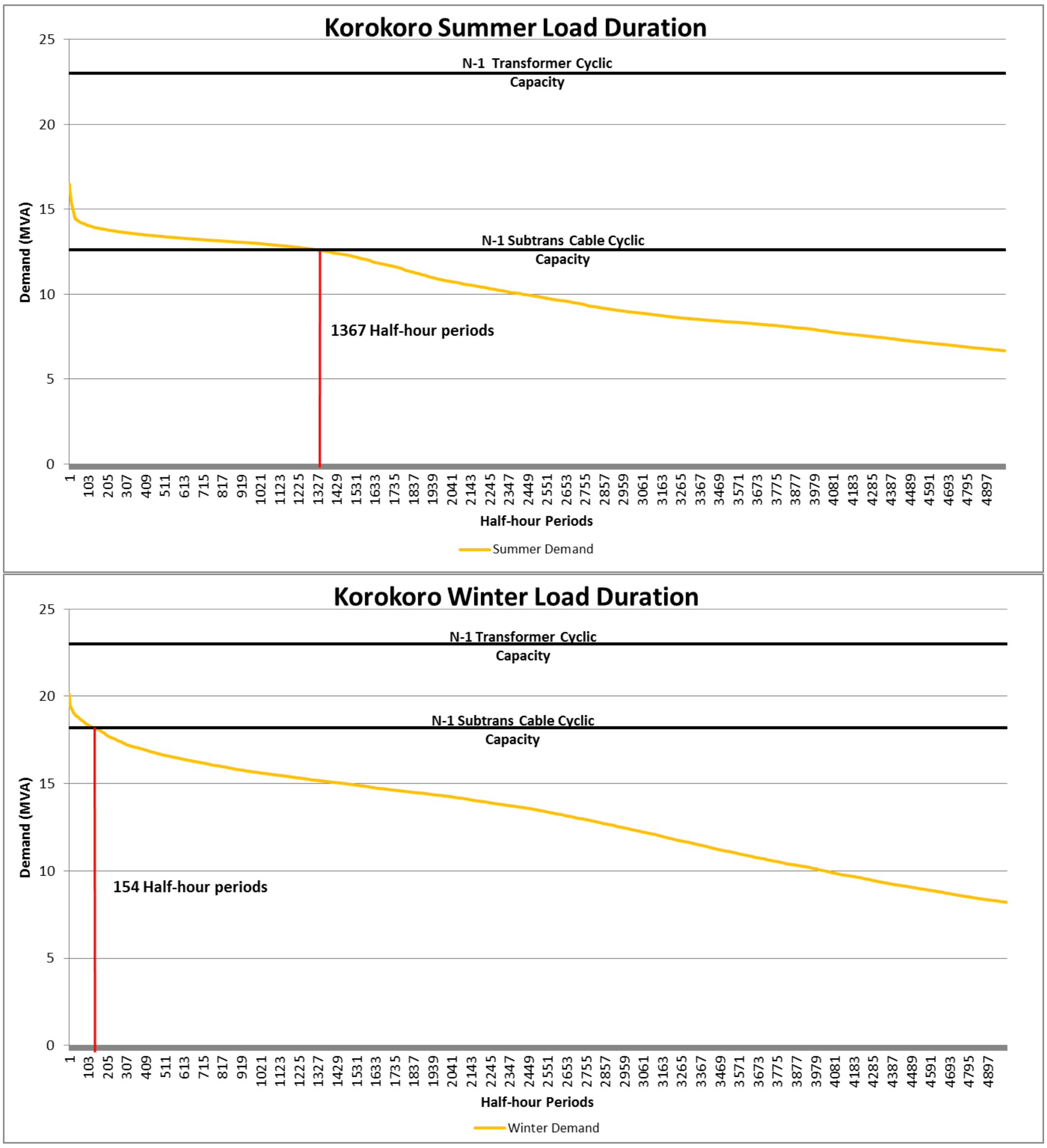


Figure 7-71 Korokoro Load Duration Curves

The load duration curve shows that a significant proportion of load is at risk during summer. The loading exceeds the N-1 cyclic ratings of the subtransmission cables for approximately 7.8% of the time in summer and 0.8% of the time in winter.

Based on the estimated growth scenarios and development within the planning period, the sustained peak load at Korokoro is forecasted as shown in Figure 7-72.

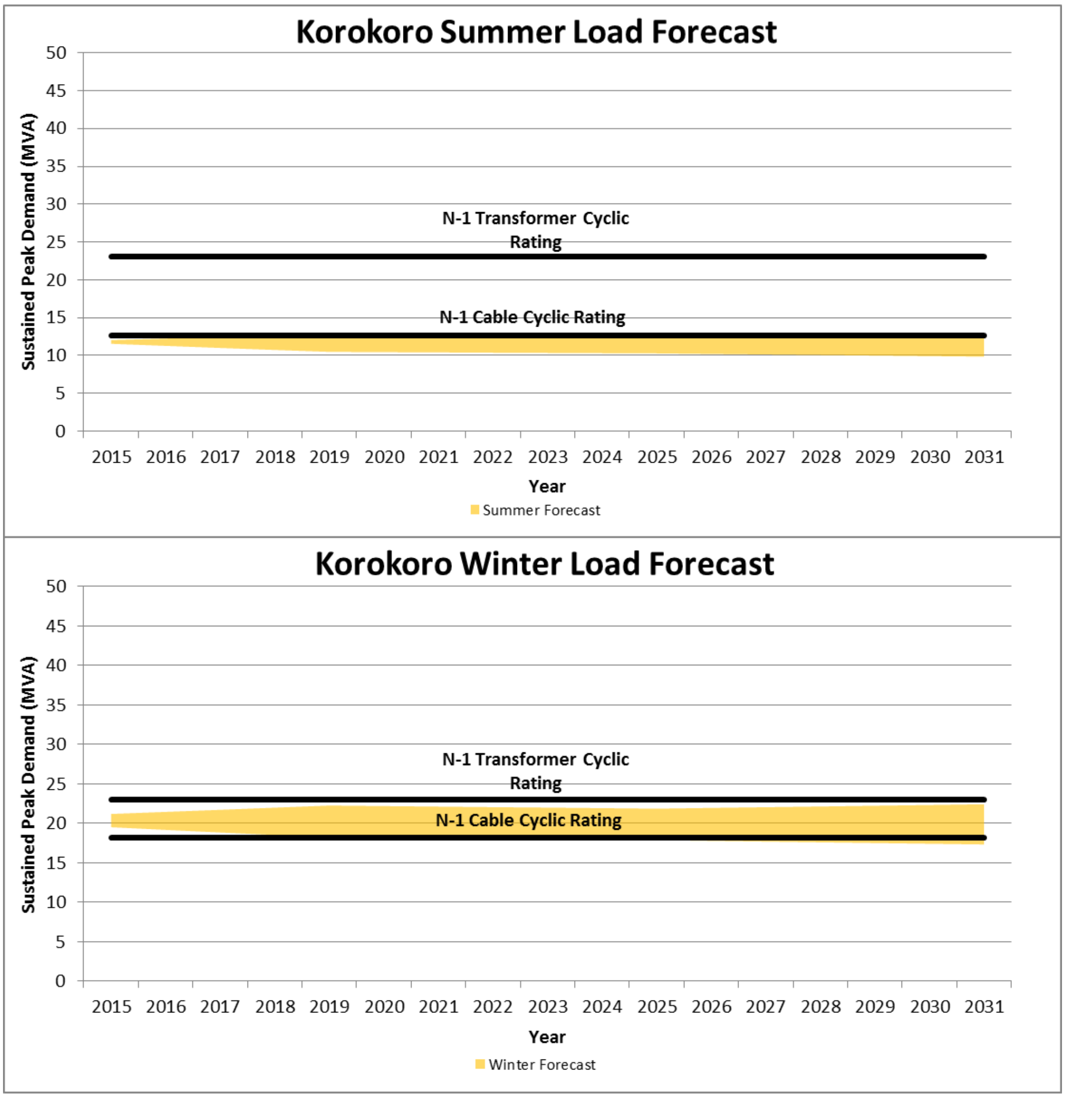


Figure 7-72 Korokoro Z/S Load Forecast

Waterloo

The sustained peak load supplied at Waterloo is expected to exceed the N-1 capacity of the subtransmission cables by summer by 2017. Without investment, Waterloo will have to be partially off-loaded from 2017 onwards following an outage to manage the capacity of the remaining subtransmission circuit. This is illustrated in Figure 7-73.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2017 (MVA)	Minimum off load for N-1 @ peak (MVA)
Waterloo A	Winter	23	17	-
	Summer	14.3	15	1-2
Waterloo B	Winter	23	17	-
	Summer	14.3	15	1-2

Figure 7-73 Waterloo Subtransmission Capacity Shortfall

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Waterloo can be forecasted for a range of growth and seasonal scenarios as shown in Figure 7-74.

The subtransmission capacity constraints are plotted for comparison.

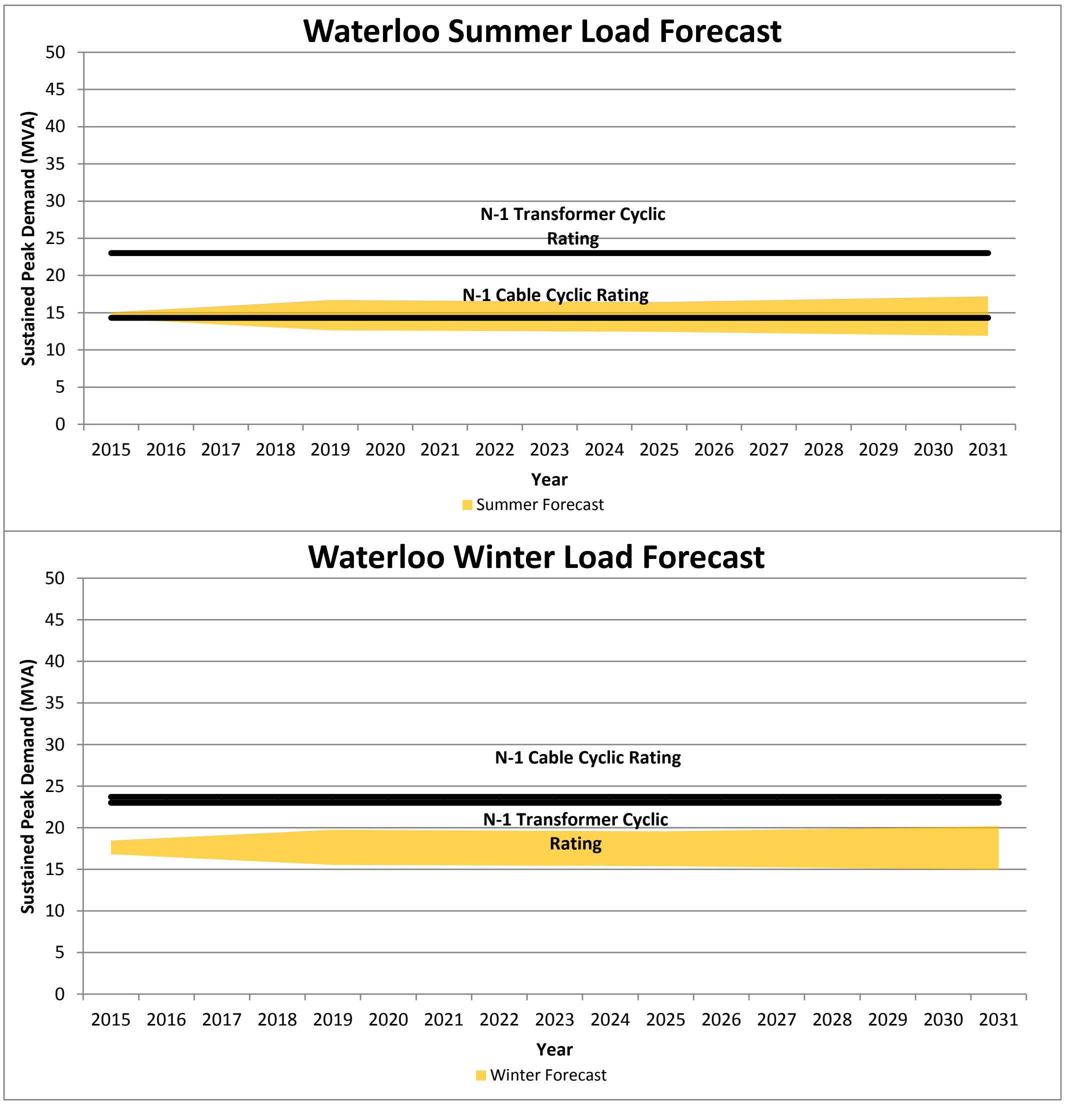


Figure 7-74 Waterloo Load Forecast

It is expected that by 2017, the sustained peak demand at Waterloo will exceed the summer cyclic N-1 ratings of the subtransmission cables.

Maidstone

The peak load supplied at Maidstone is expected to exceed the N-1 capacity of the subtransmission cables by summer by 2024. Without investment, Maidstone will have to be partially off-loaded from 2024 onwards as illustrated in Figure 7-75.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2024 (MVA)	Minimum off load for N-1 @ peak (MVA)
Maidstone A	Winter	20.7	16	-
	Summer	14.0	14	1-2
Maidstone B	Winter	20.8	16	-
	Summer	13.2	14	1-2

Figure 7-75 Maidstone Subtransmission Capacity Shortfall

Figure 7-76 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable.

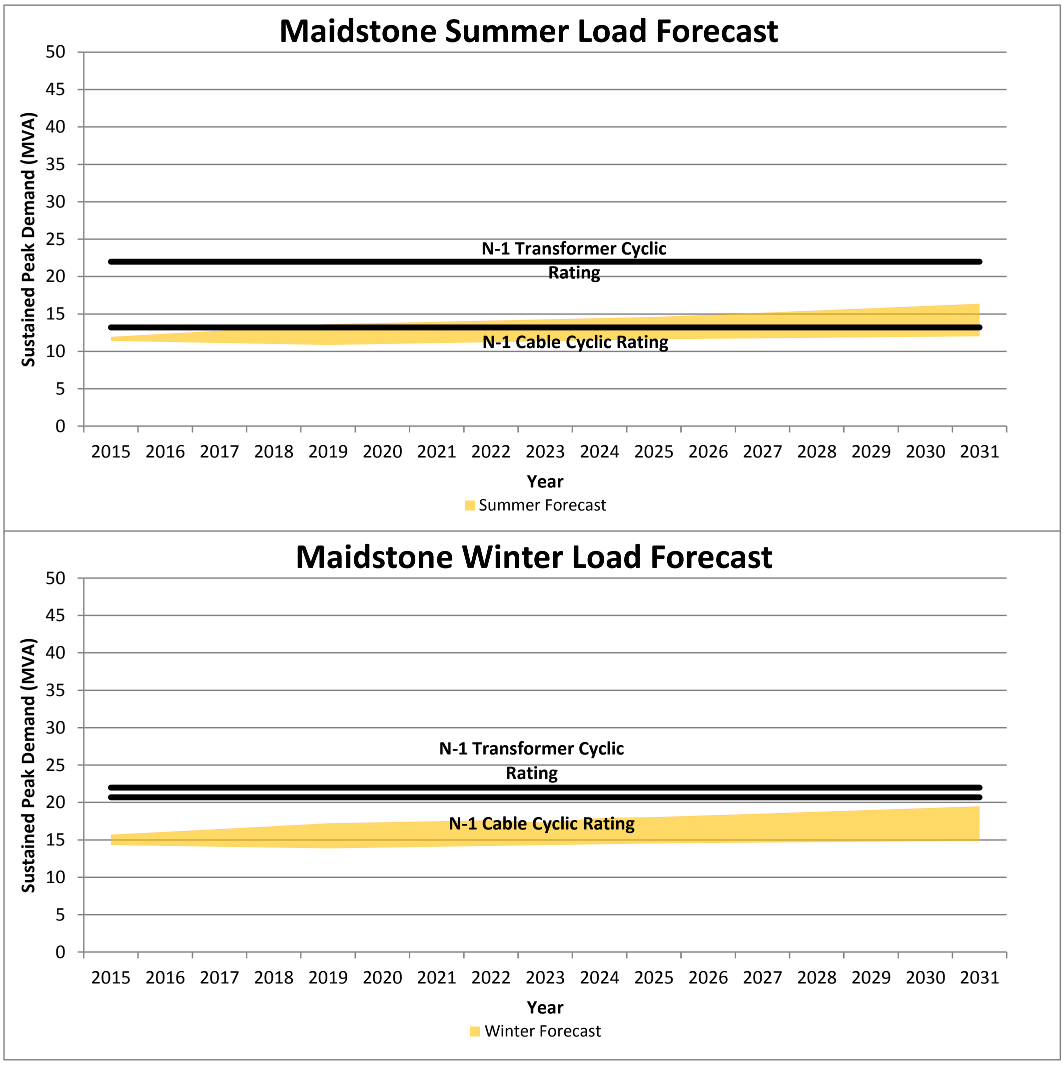


Figure 7-76 Maidstone Load Forecast

7.6.2.2 Distribution Level Development Needs

The most critical distribution level issues are those associated with overload radial feeders supplying critical loads. Figure 7-77 shows where the applicable security criteria for the various feeder configurations are breached and an estimation of when the constraints bind.

Feeder	Feeder configuration	Zone Substation	Location of worst case loading	Present	+10 years	Feeder ICP Count	Control
Current							
MAI 06	Radial	Maidstone	Leisure Centre	71%	73%	996	Monitor growth
WAT 05	Radial	Waterloo	Brook St	67%		1728	Monitor growth
WAT 03	Radial	Waterloo	Hautana St	75%	66%	469	Monitor growth
HAY 2722[1]	Radial	Haywards (GXP)	Silverstream	71%	70%	1,467	Open point shift

Figure 7-77 Distribution Level Issues

Notes to Figure 7-77

1: HAY2722 was reinforced during 2015 and the new capacity is reflected in this table.

The identified highly loaded feeders supplied from Maidstone, Waterloo and Haywards are predicted to decline in load over the planning period and may not require mitigation.

7.6.3 Northeastern Network Development Plan

More work will be undertaken to develop a comprehensive Northeastern development plan in 2016.

For budgeting purposes, an allowance has been included for various distribution level works. This allowance has been provisioned annually from 2020 onwards and will be subject to any consumer driven step change load growth in the area. The allowance is estimated based on the average distribution level reinforcement costs for a year and provides for:

- Overlay of approximately 400m of undersized 11kV cable including trenching, traffic management and reinstatement costs;
- Installation of approximately 600m of new distribution links between zones at 11kV; and
- An allowance has also been made in the first five years for the associated works involved in the Haywards and Upper Hutt GXP outdoor to indoor conversion works by Transpower.

All legacy growth and reinforcement projects planned for the Northeastern area and detailed in previous AMPs have been completed or are deferred in lieu of a consolidated strategy which will be provided by the forthcoming Northeastern area NDRP.

Figure 7-78 shows the investment plan for growth and reinforcement projects in the Northeastern Area for the planning period.

Year	Project	Estimated Cost
2017/19	Haywards supply transformers expected end-of-life (replacement by TPNZ)	N/A (Pass through)
2018	Haywards 33kV OD-ID Provision	0.05
2020	Upper Hutt OD-ID Provision	0.05
2021	Wellington Northeastern Development Strategy 2021 – Distribution Reinforcement Allowance	0.5
2022	Wellington Northeastern Development Strategy 2022 – Distribution Reinforcement Allowance	0.5
2023	Wellington Northeastern Development Strategy 2023 – Distribution Reinforcement Allowance	0.5
2024	Wellington Northeastern Development Strategy 2024 – Distribution Reinforcement Allowance	0.5
2025	Wellington Northeastern Development Strategy 2025 – Distribution Reinforcement Allowance	0.5
	Total Investment	**2.6**

Figure 7-78 Summary of Northeastern Area Investment Requirement ($M in constant prices)

7.7 Customer Initiated Projects and Relocations

These projects have been aggregated in the budget in accordance with the categories discussed below. Overall, the budgeted expenditure for 2016 of $7.7 million is higher than the 2015 actual cost of $6.9 million. This is attributed to a recent lift in consumer and developer confidence and a one off proposal requiring major network reinforcement from two zone substations.

7.7.1 New Connections

For the third consecutive year the number of residential building consents issued in the Wellington region has risen, driven by the growth in apartments within the Wellington CBD and subdivision growth along the northern belt. Figure 7-79 shows the number of building consents issued for new houses and apartments over the last six years. The 2016 budget for new connections is similar to expenditure in 2015.

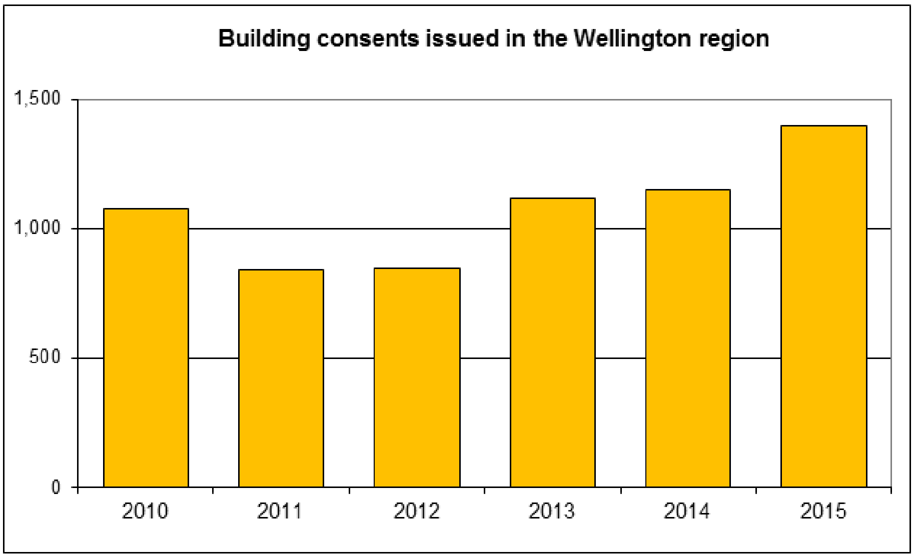


Figure 7-79 Number of Building Consents Issued in the Wellington Region

7.7.2 Substations

Budgeted spend of $3.4M for 2016 includes a $1.1M allowance for an individual MPI development project in Upper Hutt. Excluding this, the remaining forecast spend of $2.3M is in line with the past three years.

7.7.3 Subdivisions

While small and infill subdivisions remain at similar levels to previous years, developers continue a trend seen in 2015 where appetite for large scale residential (>100 lots) subdivisions is increasing, particular in the northern areas of Wellington and Porirua cities. This is partially offset by industrial property development which has slowed, and the shortage of vacant sites that can be easily converted to meet tenancy needs. The budget allocation for subdivisions in 2016 is $2.0 million compared to a 2015 spend of $1.8M.

7.7.4 Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included within the customer substation area of the customer connection forecasts.

7.7.5 Relocations

An allowance in 2016 of $1.3 million for relocation and undergrounding work, initiated from NZTA and TLAs, as well as other customer initiated relocations, has been made. Transmission Gully and redevelopment of a major SH2 intersection are critical projects in this category.

7.7.6 Non-material Works

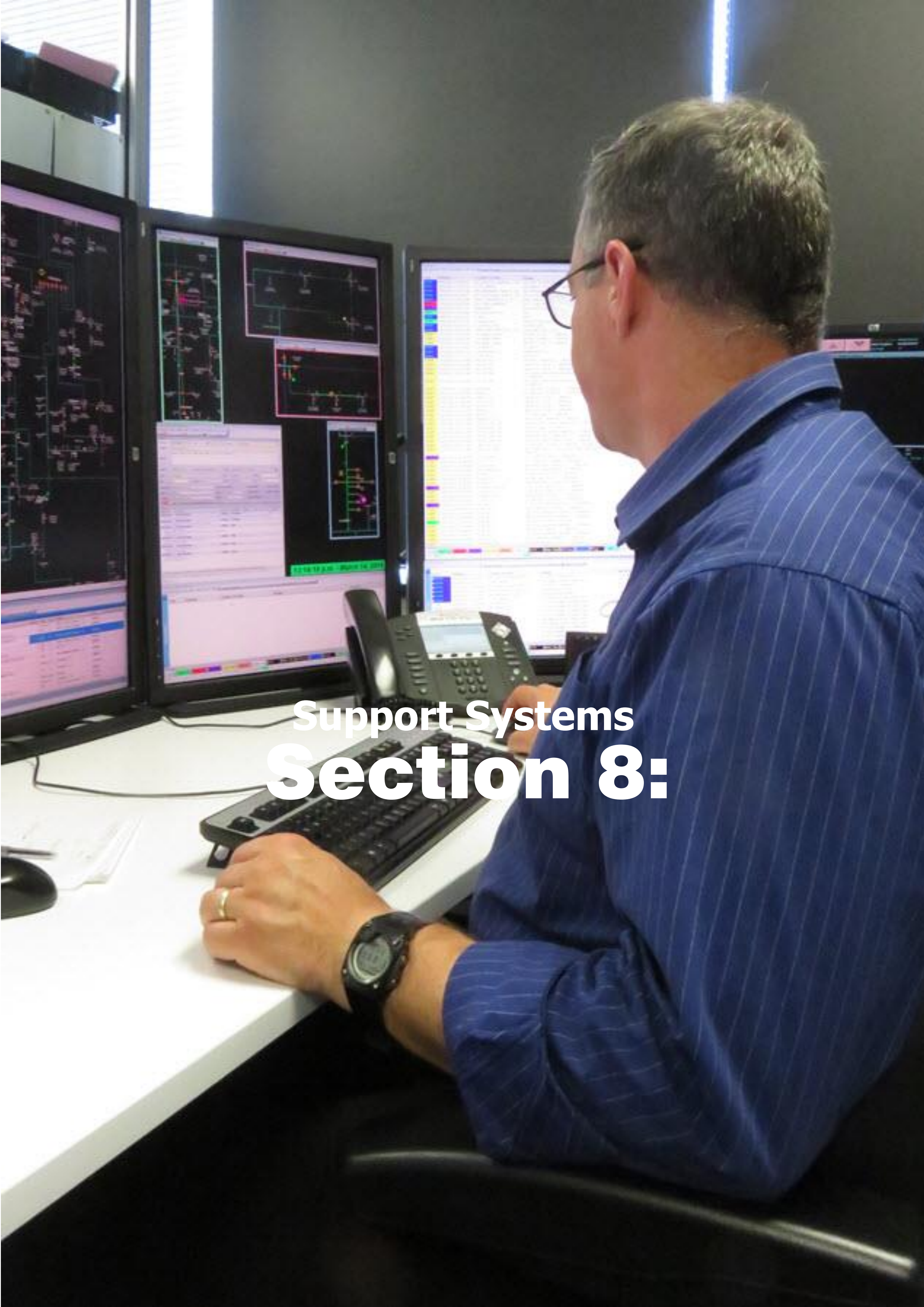
An allowance in 2016 of $250,000 has been allocated for unplanned small projects. This includes HV underground and overhead works which are outside of the Capital Works Plan but required to maintain network reliability and service levels.

7.8 Summary of the Capital Expenditure Forecasts

From the details in the sections above, Wellington Electricity's network development and growth capital expenditure forecast is summarised in the table in Figure 7-80.

Category	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Southern Area	980	3,700	4,450	5,313	1,575	2,663	2,325	2,463	638	0
Northwestern Area	288	923	180	1,595	5,285	2,180	2,040	0	0	0
Northeastern Area	0	13	38	13	163	500	500	500	500	375
Other Projects	0	180	720	720	720	720	720	720	720	540
System Growth & Reinforcement Total	**1,268**	**4,816**	**5,388**	**7,640**	**7,743**	**6,063**	**5,585**	**3,683**	**1,858**	**915**
Consumer Connection	6,236	7,186	6,778	6,610	7,103	7,751	8,506	8,986	9,249	9,249
Asset Relocations	1,206	933	977	1,049	1,110	1,192	1,289	1,344	1,363	1,363
Total	**11,069**	**17,089**	**26,229**	**26,780**	**19,628**	**23,523**	**22,858**	**22,773**	**21,997**	**21,237**

Figure 7-80 Capital Expenditure Forecasts – 2016 to 2026
($K in constant prices)



Section 8: Support Systems

8 Support Systems

Wellington Electricity invests in non-network assets to support the distribution of electricity to consumers. These assets include information systems, plant & machinery and land & buildings. This section describes the approach taken and the investment requirements for these systems over the planning period.

8.1 Wellington Electricity Information Systems

The following information describes 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 discussed.

Figure 8-1 shows where asset information is stored within Wellington Electricity's systems.

	Physical Assets	Equipment Ratings	Asset Condition	Connectivity	Customer Service
SCADA / ENMAC		✓		✓	✓
GIS	✓	✓		✓	✓
Project Wise	✓	✓			✓
Power Factory		✓		✓	
Station Ware	✓	✓			
SAP PM	✓		✓		✓
GenTrack				✓	✓
SAP (Financial)					✓

Figure 8-1 Asset Data Repositories

8.1.1 Asset Information and Operational Systems

The information systems Wellington Electricity use to manage its asset information are described below.

8.1.1.1 SCADA

A GE PowerOn Fusion Supervisory Control and Data Acquisition (SCADA) system is used to assist real time operational management of the Wellington Electricity network. The SCADA system provides operation, monitoring and control of the network at 11kV and above. Low voltage (400 volts or below) outage reports are recorded by the GE PowerOn Fusion Calltaker system utilised by the Outage Manager at the Wellington Electricity Contact Centre. The Calltaker system electronically interfaces with the Field Service Provider's dispatch system to dispatch field staff for fault response.

Main Network Control Room

During the first quarter of 2016 Wellington Electricity implemented a staged enhancement to PowerOn Fusion which further improves its functionality.

Wellington Electricity is also currently investigating upgrade options for two other systems related to the SCADA:

- Wellington Electricity currently uses TrendSCADA, a proprietary data historian tool provided with the GE PowerOn Fusion system, for network operations and planning purposes. There are a number of shortfalls with this product, such as limitations in the resolution of data that can be stored, limited ability to retrieve large datasets and a limited suite of analysis tools. The investigation will consider alternative products, such as OSI-Soft PI, which is widely used by other electricity distribution companies and which may offer greater benefits to the business and improve user-friendliness; and

- Wellington Electricity currently controls load using the Foxboro SCADA system. This system is currently at the end of its economic life and is due for replacement. Replacement options being investigated include an integrated part of the GE PowerOn Fusion system or a standalone package.

8.1.1.2 Geographic Information System (GIS)

The GIS provides a representation of the system's fixed assets overlaid on a map of the supply area. Wellington Electricity uses the GE Smallworld GIS application for planning, designing and operating the distribution system and this is the primary repository of network asset information.

The GIS links to Wellington Electricity's maintenance management system (SAP PM), GenTrack and the Field Service Provider's systems to ensure it is updated with the latest asset data and asset condition information. Asset information is updated nightly between the systems.

GIS provides a useful tool for engineering decision by making it easy to:

- Analyse asset population; and

- Carry out geospatial analysis of connectivity, SAP PM defects, maintenance and test history, and asset performance.

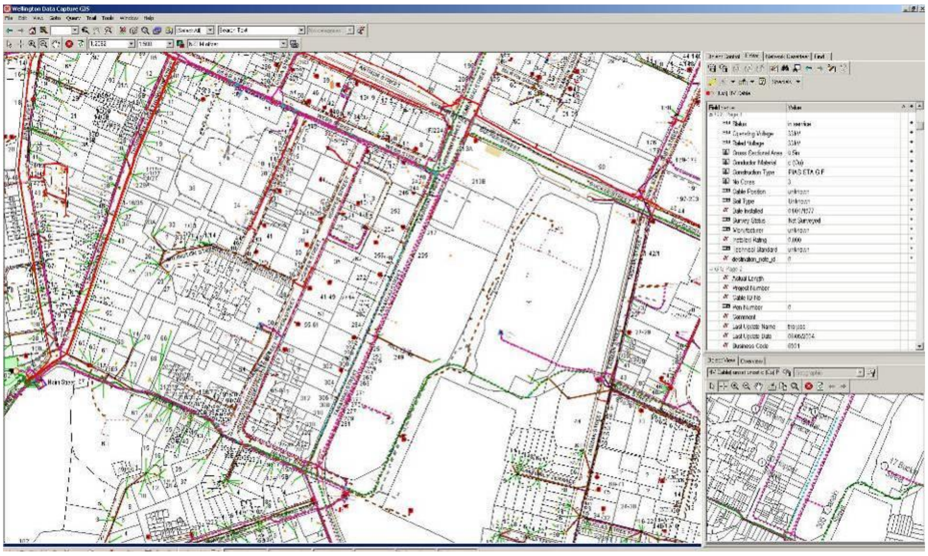


Figure 8-2 Screen Shot of Smallworld GIS system

The GIS currently includes SIAS, a web based GIS viewer that is available for staff and external contractors. Wellington Electricity plan to upgrade SIAS within the next five years to provide additional web based GIS functionality.

8.1.1.3 ProjectWise

Wellington Electricity stores all substation, system drawings and historic asset information diagrams in ProjectWise in PDF and CAD format.

8.1.1.4 DIgSILENT Power Factory

The DigSILENT Power Factory is used to model and simulate the electrical distribution network and analyse load flows for development planning, contingency planning, reliability and protection studies. The Power Factory database contains detailed connectivity and asset rating information. To ensure ongoing accuracy, the model is manually updated every quarter to include recently commissioned network assets and augmentations. Model updates are regularly distributed to design consultants to ensure consistency for commissioned studies.

8.1.1.5 Cymcap

CYMCAP (cable ampacity and simulation tool) is used to model the ratings of underground cables at all voltages for existing cables in service and new developments.

8.1.1.6 LVDrop

LV Drop is used to model low voltage electrical networks to ascertain voltage drops and loading of conductors and transformers. LV Drop contains all the relevant LV cable, conductor, transformer and ADMD information and ratings. It is used for new subdivision reticulation designs and forms part of the customer connections and planning process.

8.1.1.7 DIgSILENT Station Ware

DigSILENT Station Ware is a centralised protection setting database and device management tool. It holds relay and device information, parameters and settings files. Station Ware is accessible remotely, via the Citrix environment, to allow input and modification by approved design consultants. Protection settings are uploaded to the Station Ware database for review and approval. The settings are then distributed to commissioning personnel for application in the field.

8.1.1.8 SAP PM Asset Management System

Wellington Electricity uses the SAP Plant Maintenance (SAP PM) to plan its maintenance activities and capture asset condition data for both preventative and corrective works. This system allows Wellington Electricity to issue maintenance workpacks to service providers electronically. Maintenance results are returned electronically via a web interface. Asset data is synchronised with GIS, which allows maintenance tasks to be grouped spatially to increase efficiency.

8.1.2 GenTrack

GenTrack is used to manage ICP and revenue data, and deliver billing and connection services. GenTrack is populated and synchronised with the central ICP registry. It interfaces with the GIS and PowerOn Fusion systems to provide visibility of consumers affected by planned and unplanned network outages. GenTrack also interfaces with the SAP financial system for billing.

8.1.3 Financial Systems

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

8.2 Identifying Asset Management Data Requirements

Asset management data requirements are defined in Wellington Electricity's asset maintenance standards. The asset management data requirements are then updated when 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 who input/manage the asset information in the SAP PM information system.

8.3 Data Quality

Robust and timely asset information is needed to drive asset management activities such as development, maintenance, refurbishment and replacement. As the GIS is the central repository for Wellington Electricity's network asset information, it needs to be complete, accurate and up to date to make good asset management decisions.

Initially asset data is entered into the relevant information systems at the time the asset is created. The asset data will be updated, as required, throughout the life of the asset in systems such as SAP PM and Station Ware and transferred to the GIS during nightly updates between the systems.

Processes are in place to establish one 'source-of-truth' for each category of information and synchronisation of data between the various information systems.

To ensure data quality, Wellington Electricity continually:

- Updates data on missing or discovered assets and nameplate information stored in GIS;
- Identifies and fixes network connectivity in GIS; and
- Implements measures to improve the quality of the maintenance data reported from the field.

Data quality is managed by implementing controls such as mandatory fields, fixed selection lists when inputting data, and continually checking and verifying the data in the major systems (GIS, SAP PM). User training is provided to ensure users understand what information is required, why particular information is captured and its use within the overall asset management process. Figure 8-3 lists areas where there are limitations in the availability or completeness of asset data.

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 data is updated following inspections Periodic reporting of asset categories to identify where gaps exist and follow up with the GIS updating process to correct gaps on inspected equipment
	LV connectivity is incomplete in some places	Project to continually improve LV connectivity and create accurate representation of LV feeders and open points
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)
SAP PM	Some required data not collected for early records	Data entry into SAP PM now has mandatory fields to ensure all relevant data is captured at the time of entry into the system Historic entries being reviewed to fill in gaps
	Condition Assessment (CA) scores incorrect for early inspections arising from misunderstandings of new Field Inspectors	Standardised CA scoring and field training is in place Annual re-inspection will provide correct information from second pass
Power Factory	Historical network augmentations or customer connections may not be captured in the model	Planning engineers update the model to reflect new and updated system components on project completion Project Managers are required to submit relevant information in a timely manner at the completion of projects to allow the models to be updated to

System	Limitation	Control in Place
		reflect actual state
Station Ware	Not all station protection relay settings have been captured in Station Ware	Settings are updated at the time of projects being undertaken, or audited 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
PowerOn Fusion v5.2 (replacing ENMAC SCADA)	Not all network branches have ratings assigned to them in PowerOn Fusion, leading to possible system overload	The NCR utilises a spreadsheet of ratings based on operational scenarios. Alarm limits based on these ratings are assigned as required.

Figure 8-3 Overview of Asset Data Gaps and Improvements

8.4 Information Systems Plan

The major planned changes in network support information systems over the next five years are shown in Figure 8-4.

System	Change & Year	Benefit	Cost ($K)
GIS	Upgrade for core version 4.0 to 4.3 (2016/17)	Allows future upgrade to 5.0 Allows GIS platform to be installed for deployment of Network Viewer.	250
	SIAS upgrade to Network Viewer (2016/17)	Allows better web based functionality, and can be directly read by the B4UDig automated plan release system.	150
GenTrack	Upgrade of GenTrack 3.5 and Oracle 9.2 to current versions (2016/17)	Allows for removal of unsupported software and expired hardware infrastructure.	770
PowerOn Fusion v5.2	Upgrade Stage 2 (2016/17)	Functional enhancements to improve the user experience and OMS tools	400
Load Control Master Station	Replacement Foxboro Master Station (2016/17)	Replacement of legacy software and improved functionality	400

Figure 8-4 Overview of Major System Improvements

8.5 Plant and Machinery Assets

Leased vehicles are typically replaced every three years in accordance with Wellington Electricity's Motor Vehicle Policy. There is provision in the 2016 non-network CAPEX programme to extend the Deuar pole-testing license. Other test equipment and tools are replaced as required, for example power quality and partial discharge test sets. There are no other material investments planned for non-network plant and machinery.

8.6 Land and Building Assets

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.

8.7 Non-Network Asset Expenditure Forecast

Routine Expenditure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Software and Licenses	1,331	1,134	1,139	963	982	1002	1022	1043	1063	1084
IT Infrastructure	182	155	156	132	134	137	139	142	145	148
Total Non-network Capital Expenditure	**1,513**	**1,290**	**1,295**	**1,094**	**1,116**	**1,139**	**1,161**	**1,185**	**1,208**	**1,232**
System Operations and Network Support	4,350	4,353	4,358	4,361	4,363	4,364	4,367	4,369	4,370	4,371
Business Support	11,729	11,300	11,311	11,320	11,326	11,327	11,335	11,341	11,343	11,345
Total Non-network Operational Expenditure	**16,080**	**15,653**	**15,669**	**15,681**	**15,689**	**15,691**	**15,702**	**15,711**	**15,713**	**15,716**

Figure 8-5 Non-Network Expenditure Forecast ($K in constant prices)

Section 9:
Expenditure Summary

9 Expenditure Summary

This section provides an overview of Wellington Electricity's forecast capital and operational expenditure over the planning period, in order to implement this AMP.

9.1 Capital Expenditure 2016-2026

9.1.1 Consumer Connections

The total forecast consumer connection capital expenditure for 2016 to 2026, as discussed in Section 7, is presented in Figure 9-1.

Consumer Type	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Substation	3,732	4,307	4,060	3,959	4,257	4,650	5,107	5,398	5,557	5,557
Subdivision	1,095	1,264	1,191	1,161	1,249	1,364	1,498	1,584	1,631	1,631
High Voltage Connection	120	139	131	127	137	150	164	174	179	179
Residential Customers	1,214	1,401	1,321	1,288	1,385	1,513	1,661	1,756	1,808	1,808
Public Lighting	75	75	75	75	75	75	75	75	75	75
Total	**6,236**	**7,186**	**6,778**	**6,610**	**7,103**	**7,751**	**8,506**	**8,986**	**9,249**	**9,249**

Figure 9-1 Consumer Connection Capital Expenditure Forecast ($K in constant prices)

9.1.2 System Growth

The total forecast capital expenditure for system growth and security of supply for 2016 to 2026, as discussed in detail in Section 7, is presented in Figure 9-2.

Asset Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission	288	1,488	2,275	1,200	0	0	0	0	0	0
Zone Substations	980	3,088	1,763	4,125	5,163	850	850	850	638	0
Distribution Poles and Lines	0	0	0	0	0	0	0	0	0	0
Distribution Cables	0	60	630	1,595	1,860	4,493	4,015	2,113	500	375
Distribution Substations	0	0	0	0	0	0	0	0	0	0
Distribution Switchgear	0	180	720	720	720	720	720	720	720	540
Other Network Assets	0	0	0	0	0	0	0	0	0	0
Total	**1,268**	**4,816**	**5,388**	**7,640**	**7,743**	**6,063**	**5,585**	**3,683**	**1,858**	**915**

Figure 9-2 System Growth Capital Expenditure Forecast
($K in constant prices)

9.1.3 Asset Replacement and Renewal

The total forecast capital expenditure for asset replacement and renewal for 2016 to 2026 is presented in Figure 9-3. This includes provision for replacements that arise from condition assessment programmes during the year.

Asset Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission	300	300	300	300	300	300	300	1,175	2,925	300
Zone Substations	930	2,070	1,815	1,260	1,480	250	250	250	250	250
Distribution Poles and Lines	8,485	7,250	6,495	6,182	6,000	8,900	8,900	8,900	8,900	8,900
Distribution Cables	1,115	1,255	1,294	1,190	1,644	2,436	3,030	3,626	4,224	4,823
Distribution Substations	3,375	2,375	2,500	2,500	2,625	3,000	3,500	3,500	3,500	3,500
Distribution Switchgear	4,617	4,465	3,890	3,525	3,150	3,123	3,650	4,150	4,150	4,150
Other Network Assets	3,913	2,333	3,088	3,034	2,506	2,075	1,900	1,900	1,900	1,900
Total	**22,735**	**20,048**	**19,382**	**17,991**	**17,705**	**20,084**	**21,530**	**23,501**	**25,849**	**23,823**

Figure 9-3 System Asset Replacement and Renewal Capital Expenditure Forecast
($K in constant prices)

9.1.4 Asset Relocations

The forecast asset relocation capital expenditure, primarily related to roading projects, is presented in Figure 9-4.

Programme	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Roading Relocations	1,206	933	977	1,049	1,110	1,192	1,289	1,344	1,363	1,363
Total	**1,206**	**933**	**977**	**1,049**	**1,110**	**1,192**	**1,289**	**1,344**	**1,363**	**1,363**

Figure 9-4 Asset Relocation Capital Expenditure Forecast
($K in constant prices)

9.1.5 Reliability, Safety and Environment

Asset management expenditure that is not directly the result of asset health drivers is categorised into quality of supply and other reliability, safety and environmental expenditure. Quality of supply projects target poorly performing feeders. Other reliability, safety and environmental projects include the seismic programme and other resilience work. The total forecast capital expenditure for these categories is presented in Figure 9-5.

Programme	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Worst Performing Feeders	1,631	1,232	1,300	863	1,030	900	919	963	969	1,100
Total Quality of Supply	**1,631**	**1,232**	**1,300**	**863**	**1,030**	**900**	**919**	**963**	**969**	**1,100**
Seismic Programme	944	1,010	988	1,016	1,193	1,288	1,336	TBD	TBD	TBD
33kV Temporary Line Corridor Components	300	300	150	0	TBD	TBD	TBD	TBD	TBD	TBD
Total Other Reliability, Safety and Environment	**1,244**	**1,310**	**1,138**	**1,016**	**1,193**	**1,288**	**1,336**	**0**	**0**	**0**

Note: TBD figures to be determined following 2016 resiliency project study.

Figure 9-5 Reliability, Safety and Environmental Capital Expenditure 2016-2026
($K in constant prices)

9.1.6 Non-network Assets

The forecast capital expenditure for non-network assets is presented in Figure 9-6.

Routine Expenditure	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Software and Licenses	1,331	1,134	1,139	963	982	1,002	1,022	1,043	1,063	1,084
IT Infrastructure	182	155	156	132	134	137	139	142	145	148
Total Non-network Assets	**1,513**	**1,290**	**1,295**	**1,094**	**1,116**	**1,139**	**1,161**	**1,185**	**1,208**	**1,232**

Figure 9-6 Non-Network Asset Capital Expenditure Forecast
($K in constant prices)

9.1.7 Capital Expenditure Summary

Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Consumer Connection	6,236	7,186	6,778	6,610	7,103	7,751	8,506	8,986	9,249	9,249
System Growth	1,268	4,816	5,388	7,640	7,743	6,063	5,585	3,683	1,858	915
Asset Replacement & Renewal	22,735	20,048	19,382	17,991	17,705	20,084	21,530	23,501	25,849	23,823
Asset Relocations	1,206	933	977	1,049	1,110	1,192	1,289	1,344	1,363	1,363
Reliability, Safety & Environment (other)	1,244	1,310	1,138	1,016	1,193	1,288	1,336	0	0	0
Quality of Supply	1,631	1,232	1,300	863	1,030	900	919	963	969	1,100
Subtotal - Capital Expenditure on Network Assets	**34,320**	**35,525**	**34,963**	**35,169**	**35,884**	**37,278**	**39,165**	**38,477**	**39,288**	**36,450**
Non-Network Assets	1,513	1,290	1,295	1,094	1,116	1,139	1,161	1,185	1,208	1,232
Total – Capital Expenditure on Assets	**35,833**	**36,815**	**36,258**	**36,263**	**37,000**	**38,417**	**40,326**	**39,662**	**40,496**	**37,682**

Figure 9-7 Capital Expenditure Forecast – 2016 to 2026 ($K in constant prices)

9.2 Operational Expenditure 2016-2026

A breakdown of forecast preventative maintenance expenditure by asset category is shown in Figure 9-8. This budget is relatively constant, and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

Asset Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission	116	116	116	116	116	116	116	116	114	114
Zone Substations	304	302	293	272	261	271	266	271	261	271
Distribution Poles and Lines	444	441	439	437	434	433	431	429	428	427
Distribution Cables	0	0	0	0	0	0	0	0	0	0
Distribution Substations	435	435	435	435	435	435	435	435	435	435
Distribution Switchgear	729	728	728	727	727	727	727	727	727	727
Other Network Assets	275	275	220	220	218	218	218	218	218	218
Total	**2,303**	**2,297**	**2,231**	**2,207**	**2,191**	**2,200**	**2,193**	**2,196**	**2,183**	**2,192**

Figure 9-8 Preventative Maintenance by Asset Category – 2016 to 2026 ($K in constant prices)

The forecast corrective maintenance expenditure by asset category is shown in Figure 9-9. This excludes capitalised maintenance, which is incorporated into Figure 9-3. These forecasts are based on historical trends and forecast asset replacements, however year on year variances across the different asset categories will occur depending on the nature of the corrective maintenance that is required in any given year.

Asset Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Subtransmission	0	0	0	0	0	0	0	0	0	0
Zone Substations	164	163	163	165	166	168	170	173	174	177
Distribution Poles and Lines	913	832	824	763	764	858	866	874	880	880
Distribution Cables	163	169	175	181	187	194	200	207	215	222
Distribution Substations	960	872	938	940	937	980	977	974	971	968
Distribution Switchgear	740	734	727	722	715	709	703	698	692	686
Other Network Assets	143	205	208	240	191	271	278	305	338	335
Total	**3,083**	**2,975**	**3,035**	**3,011**	**2,960**	**3,180**	**3,194**	**3,231**	**3,270**	**3,268**

Figure 9-9 Corrective Maintenance by Asset Category – 2016 to 2026 ($K in constant prices)

The total forecast operational expenditure for 2016 to 2026 is shown in Figure 9-10.

Category	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Service interruptions & emergencies maintenance	4,151	4,139	4,127	4,115	4,103	4,091	4,079	4,067	4,055	4,043
Vegetation management	1,425	1,432	1,439	1,446	1,453	1,460	1,467	1,474	1,481	1,488
Routine & corrective maintenance and inspection maintenance	7,464	7,375	7,424	7,457	7,500	7,558	7,630	7,721	7,834	8,074
Asset replacement & renewal maintenance	1,157	1,173	1,158	1,173	1,195	1,216	1,240	1,263	1,282	1,293
Subtotal –Operational Expenditure on Network Assets	**14,197**	**14,119**	**14,148**	**14,191**	**14,251**	**14,325**	**14,416**	**14,525**	**14,652**	**14,898**
Non-network Operational Expenditure	16,080	15,653	15,669	15,681	15,689	15,691	15,702	15,711	15,713	15,716
Total – Operational Expenditure	**30,277**	**29,772**	**29,817**	**29,872**	**29,940**	**30,016**	**30,118**	**30,235**	**30,366**	**30,614**

Figure 9-10 Operational Expenditure Forecast – 2016 to 2026 ($K in constant prices)

Appendix A Assumptions

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Demand and Consumption	Growth at higher levels may bring forward network reinforcement investment, or conversely a decrease in demand growth may lead to deferral of reinforcement investment.	Growth in peak demand will continue to be lower than the national average and will remain steady through the forecast period. Overall consumption of electricity (kWh volume) is forecast to continue decreasing for two more years before stabilising.	Measured system loadings and load analysis indicate minor maximum demand growth in some areas but energy volumes declining across the network as a whole. Low to moderate levels of growth in the housing sector.
Capital Expenditure - Resilience	Investment levels may increase in response to legislative changes or in response to stakeholder requirements.	Allowance has been made for seismic building reinforcement in order to meet legislative requirements, and a small nominal amount for emergency 33kV corridor components.	Aligns with the Commission’s initial DPP approach of resiliency expenditure being funded from current allowances, which limits resilience speed timing.
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 steady. 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 well known, steady and no "step change" in expenditure is expected.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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 four years. Managing mature network assets, the routine of inspection and servicing is not likely to change significantly.	The inspection programme is defined by comprehensive maintenance standards covering all asset classes. Rates are set in the Field Services Agreement.
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 two years. Aging assets may lead to higher levels of reactive maintenance required longer term.	Reactive maintenance rates defined in Field Services Agreement, which 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 forecast amounts may increase or decrease.	The 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 is based on increases in costs due to annual forecast inflation and price escalation as follows: 2017 (1.3%); 2018 to 2026 (2.0%).	The rates from 2017 to 2019 were based on RBNZ forecasts. The rates for the years thereafter are based on the midpoint of the RBNZ's target inflation range.
Quality targets	Any increase in quality targets, or alteration in the assessment method, may lead to increased level of investment to maintain network performance.	Network reliability performance targets for 2015/16 to 2019/20 were set by the Commission's 2014 DPP Determination. For simplicity it is assumed that the targets remained unchanged by the 2019 Determination	The targets adopted in this plan align with the Commission's 2014 determination, and reflect Wellington Electricity's intention to maintain network reliability at current levels.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Regulatory environment	A change to the regulatory environment may lead to increased or decreased ability to recover on investments.	The regulatory environment will continue to incentivise shareholders to invest in the network to ensure a sustainably profitable business. New requirements relating to the HSW act and proposed DDA will not significantly alter costs.	The expected impact of the 2014 DPP reset has been assessed, providing stability through to 2020. As Wellington Electricity is committed to implementing best practice in workplace health and safety, compliance with the HSW Act will not materially increase costs. The impact of the proposed DDA is yet to be determined, however this assumption is for simplicity.
Transmission Network	A change to the configuration or capability of the transmission system could lead to a requirement 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 changes to the grid that will significantly impact Wellington Electricity during the planning period, other than those identified in Section 7.
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. The outcome of current consultation by the Electricity Authority on TPM is yet to be determined.
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.	Global economic outlook is weak, offset by a lower New Zealand dollar, leading to stability in the price paid for equipment and materials. Assumptions of regional GDP growth are supported by observations of demand on the network and local business activities.

Area	Possible impact and variation to plan	Assumption	Reason for 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 AMP. 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 by 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 during the early years of this plan. Trends in the area of disruptive technology are being closely monitored.
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.	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 NZS 7901 and promoting a culture of incident reporting and safety awareness.

Appendix B Update from 2015 Plan

During the past year, Wellington Electricity has continued the review of its asset management strategy and practices. Progress against the gaps identified in the 2015 AMP is shown in the table below.

2015 AMP Section	Item	Description
0	Impact of 2014 DPP Reset Decision	Review expenditure forecasts in light of the November 2014 DPP reset for the 2015-2020 period.
		Complete: Wellington Electricity is forecasting capital and operating expenditure to ensure it continues to provide the quality of service required by consumers.
2.5.1	Engagement Initiatives	Development of a new website and a smartphone application.
		In Progress: New website was developed in 2015 and is now live. A smartphone application is in beta testing.
2.8.1	Field Services	Negotiate new field services agreement.
		Complete: New field services agreement signed and effective from January 2016.
2.10	Use of System Agreement	Finalise the drafting of a revised Use of System Agreement in line with the model agreement prepared by the Electricity Authority and commence negotiations with retailers using the network.
		On Hold: This work is on hold pending the Electricity Authority's current consultation on Default Distribution Agreements.
2.8.1	Contact Centre	Renegotiate the contract for the outsourced Wellington Electricity contact centre.
		Complete: Contract renegotiated, and additional KPIs established around outage notification.
3.4.1.1	SCADA	Upgrade the SCADA master station software to PowerOn Fusion.
		Complete. PowerOn Fusion system went live in February 2016.
3.4.1.1	SCADA	Prepare a business case for introduction of new software to replace the TrendSCADA data historian tool.
		On Hold. Project was placed on hold due to the implementation of PowerOn Fusion. Will be revisited during 2016.

2015 AMP Section	Item	Description
3.4.1.1	Automatic Load Control System	Undertake further investigation and planning into the replacement for the Foxboro automatic load control system.
		Ongoing: Pricing has been obtained for possible replacements of the load control system.
3.4.4	Data validity and improvement	Ongoing connection point (ICP) data validation and connectivity improvements is to be made in the GIS as part of an ongoing programme, as well as continuous updating of records captured during field inspections, such as nameplate data of equipment.
		In Progress: This work is ongoing, with ICP data for 1,355 substation sites out of 4,304 having been updated so far.
5.5.4	Seismic Assessment of Equipment and Buildings	Ongoing assessment of nominated substation buildings in accordance with the seismic assessment programme.
		In Progress: All remaining pre-1976 buildings had IEPs undertaken during 2015, with some DSAs still required to be completed. A forward work plan has been developed, and work will be tendered for reinforcement according to that plan.
5.5.5	33kV Overhead Emergency Corridors	Completion of designs for the remaining overhead subtransmission routes, and consultation with WCC to gain approval for these routes.
		In Progress: All except one Wellington City route have been developed. Surface foundations were type tested in 2015, with the designs to be refined during 2016. Consultation with WCC will occur during 2016.
9.4	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.
		In Progress: Volume 1 of the Network Development Plan, covering the Wellington city area, and Volume 2, covering the Northwestern area, have been completed.
9.5.2.1	Resilience of Central Park to HILP events	In conjunction with Transpower, finalise the Central Park HILP study in order to provide the information needed to develop plans to increase the resilience of this GXP to HILP events and mitigate Wellington Electricity's vulnerability to such events.

2015 AMP Section	Item	Description
		In Progress: Wellington Electricity has an agreed plan and is working closely with Transpower to improve the resilience of Central Park.
10.1	Asset Lifecycle Planning	Continued development of asset lifecycle plans for all asset categories.
		In Progress: Development of detailed asset strategies to be continued in 2016.
10.3.2	Subtransmission Health and Criticality Analysis	An options study will be undertaken during 2015 to assess solutions for removing the Evans Bay subtransmission circuits from service.
		In Progress: Work is underway to evaluate options including the installation of a 33kV bus at Evans Bay. Health concerns on the Evans Bay circuits have been localised to Circuit 1.
10.4.7.1	SCADA Assets	The PAS will be decommissioned and replaced with standard station RTUs.
		In Progress: This replacement project is currently underway, for completion during 2016.
10.4.8.2	Load Control Replacement Strategy	Wellington Electricity is reviewing its load control strategy, which may recommend additional investment in load control assets.
		In Progress: A draft strategy has been developed for the future of the overall load control system on the network. Work to refine and gain approval for this strategy will take place in 2016.
10.5.2	Operating Expense by Asset Category	Wellington Electricity is 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.
		In Progress: Further work has been undertaken to split future OPEX forecasts into maintenance type (preventative, corrective, reactive, etc) by asset categories by age, as part of the asset strategies that have been developed.

Figure B-1 Progress Against Actions Identified in 2015 AMP

Comparisons between forecast expenditure from the 2015 AMP and the actual expenditure for the 2015/16 regulatory year are shown below in Figure B-2 for operational expenditure and Figure B-3 for capital expenditure.

Expenditure Category	2015/16 Forecast from 2015 AMP	2015/16 Actuals	Variation
Service Interruptions and Emergencies	3,655	4,186	+$531
Vegetation Management	1,648	1,431	-$217
Routine and Corrective Maintenance and Inspection	9,118	6,742	-$2,376
Asset Replacement and Renewal	903	1,155	+$252
System Operations and Network Support	4,354	4,344	-$10
Business Support	11,221	11,712	+$491
Operational expenditure	**30,899**	**29,570**	**-$1,329**

Figure B-2 Comparison of Operational Expenditure Against 2015 AMP Forecasts ($K, Forecast in Nominal Dollars)

Operating expenditure was approximately 4% lower than forecast mainly due to reduced routine and corrective maintenance and inspection costs. Defect remediation works continue to be undertaken on a regular basis, some of which was capitalised due to the nature of remediation works required.

Expenditure Category	2015/16 Forecast from 2015 AMP	2015/16 Actuals	Variation
Consumer Connection	8,015	5,724	-$2,291
System Growth	825	504	-$321
Asset Replacement and Renewal	17,978	19,383	+$1,405
Asset Relocations	1,143	1,336	+$193
Reliability, Safety and Environment	2,896	1,126	-$1,770
Expenditure on Non-network Assets	2,100	1,748	-$352
Capital Expenditure	**32,957**	**29,822**	**-$3,135**

Figure B-4 Comparison of Capital Expenditure Against 2015 AMP Forecasts ($K, Forecast in Nominal Dollars)

Significant variations between forecast capital expenditure and actual expenditure were as follows:

- Two major consumer-initiated projects did not proceed as quickly as had been anticipated, resulting in a variation of -$2.5 million in Consumer Connection;

- The seismic reinforcement of Newtown Substation was placed on hold, in order to investigate more cost-effective means of strengthening this building, resulting in a variation of -$1.0m in Reliability, Safety and Environment; and

- Approximately $1.1m of Asset Renewal actual expenditure had been categorised as Reliability, Safety and Environmental Projects in the 2015 AMP.

Appendix C Description of Development Plan Projects

Replace the Frederick Street Subtransmission Cables

In late 2015, a project was enacted to reinforce the Frederick Street subtransmission cables. These cables were derated by approximately 5.5MVA per circuit due installation in close proximity to two 11kV circuits from Nairn Street. These two Nairn Street 11kV cables share a trench with the Frederick Street 33kV cables for approximately 50m along Taranaki Street, between Bidwell Street and Hankey Street.

Works were executed to remove pinch point and increase the subtransmission capacity at Frederick Street to reduce the duration of breach of N-1 capacity and allow more efficient management of the network during contingency events. These works also provide sufficient capacity to cater for growth until the Frederick Street subtransmission cables are completely replaced.

Replacement of the Frederick Street subtransmission cables will require overlay of the existing gas filled 33kV circuits supplying Frederick Street.

These cables are to be replaced with high capacity XLPE cables (800mm2 Al XLPE) similar to the recent Palm Grove subtransmission cable replacement project. Installation of sufficient conduit through the Wellington CBD will pose a number of issues:

- Traffic management, trenching and reinstatement costs in the CBD area will be expensive;
- A final cable route will need significant exploratory work such as the use of ground penetrating radar and pot-holing to establish the presence of obstructions;
- Sufficient room for installation of 6x150mm conduits in two trefoil arrangements with sufficient separation may not be possible in some areas, constraining the possible capacity of the cable; and
- Construction will involve significant complications with access for plant and machinery, pedestrian access and securing the site.

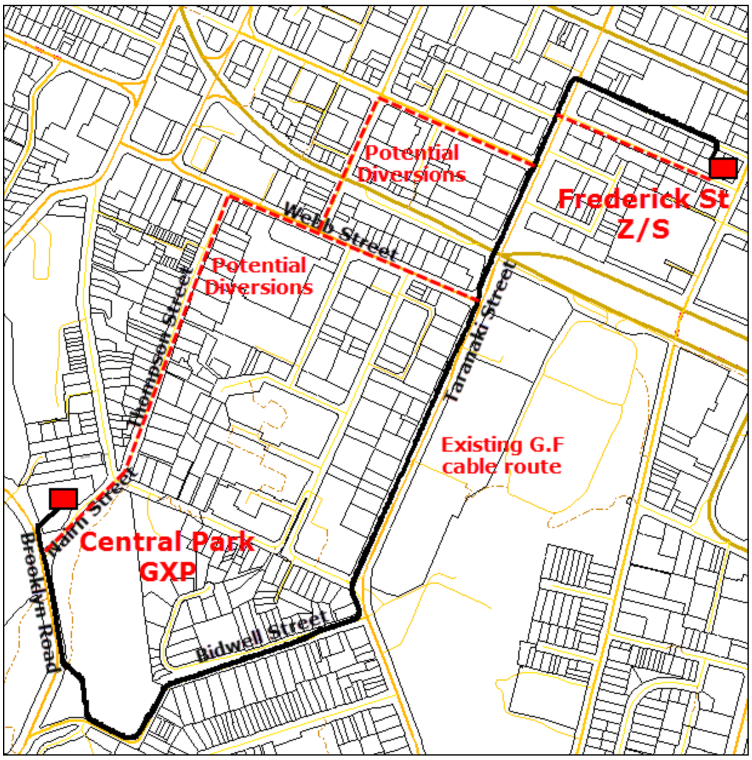


Figure C-1 Proposed Cable Route

The Palm Grove subtransmission replacement project revealed the Bidwell Street section to have insufficient room for installation of further conduit due to the number of existing buried services present. Potential deviations around constrained sections are shown however further investigation will be required to determine a feasible cable route.

Based on the new Palm Grove subtransmission cables, a minimum rating of 40MVA for the new Frederick Street subtransmission cables is a reasonable assumption.

As part of these works, a new fibre cable can be installed and protection and SCADA communications can be migrated from the existing copper pilot infrastructure. This will support replacement of the existing electromechanical relays protecting the Frederick Street 33kV cables and transformers.

Figure C-2 provides the estimated cost for these works.

Project Description	Cost ($K)	Year Investment Required
Frederick Street Subtransmission Cable Replacement and Protection Upgrade **Ref 18-001**	4,100	2018

Figure C-2 Cost Estimate Replacement of the University Subtransmission Circuits

Replace the Palm Grove Transformers

Subtransmission capacity into Palm Grove is constrained by the ratings of the 33/11kV transformers (24MVA cyclic). The Palm Grove subtransmission cables were recently replaced with new high capacity XLPE cables with a rating of approximately 36MVA. These transformers, while highly utilised, are generally in good condition and could be relocated to another site.

To increase the available capacity at Palm Grove, the existing transformers need to be replaced. This will involve the following works:

- New 30MVA units can be purchased and installed at Palm Grove. The units shall have facility for up-rating by installation of forced cooling; and
- New 11kV cable tails from the new transformers to the 11kV switchboard incomers will be required to suit the new higher rated units.

The old Palm Grove units can be relocated to replace the Evans Bay units which are in poorer condition

A number of challenges that will be faced during construction, particularly with transport and installation of the new transformers at Palm Grove. The most feasible option is to have the transformers delivered by barge to the Island Bay area. From here, there are a number of roads with overhead trolley bus DC cabling which will have to be negotiated. This may be avoidable if, as predicted, the trolley bus system will be de-commissioned prior to these works. Transport of the Palm Grove transformers to Evans Bay can be achieved by barge from Island Bay to the Evans Bay wharf.

Physical installation of the transformer will be complicated by the expected size of the 30MVA units which may be in excess of the available area in the existing transformer bays. A possible solution may be to install the transformer radiator fins external to the transformer bay aiding cooling. Cranage and lifting requirements during transport and installation may also be complicated due to the limited space available at the Palm Grove zone substation site and Palm Grove road.

Figure C-3 provides the estimated cost for replacement of the Palm Grove transformers.

Project Description	Cost ($K)	Year Investment Required
Replacement of the Palm Grove Transformers **Ref 19-002**	3,100	2019

Figure C-3 Cost Estimate for Replacement of the Palm Grove Transformers

Install a new 33kV Bus at Evans Bay

Straight replacement of the subtransmission cables supplying Evans Bay zone substation is not the most cost effective option. The 110kV oil filled cables currently supplying 8 Ira Street may be an option for reducing the cost of replacing the cables.

The oil filled cables are installed between Central Park and Evans Bay where they terminate onto pothead structures prior to transitioning to gas filled cables which continue on to 8 Ira Street. These cables have a capacity of 30MVA each which is sufficient for supply of the aggregate peak demand recorded at Evans Bay and 8 Ira Street. One of the Evans Bay 33kV cables is still in good condition and can also be terminated to the 33kV bus to provide additional capacity.

To facilitate this, a 33kV bus will be required at Evans Bay with feeders supplying the Evans Bay transformers and the existing gas filled cables supplying 8 Ira Street. Figure C-4 shows the potential configuration of the Evans Bay subtransmission circuits.

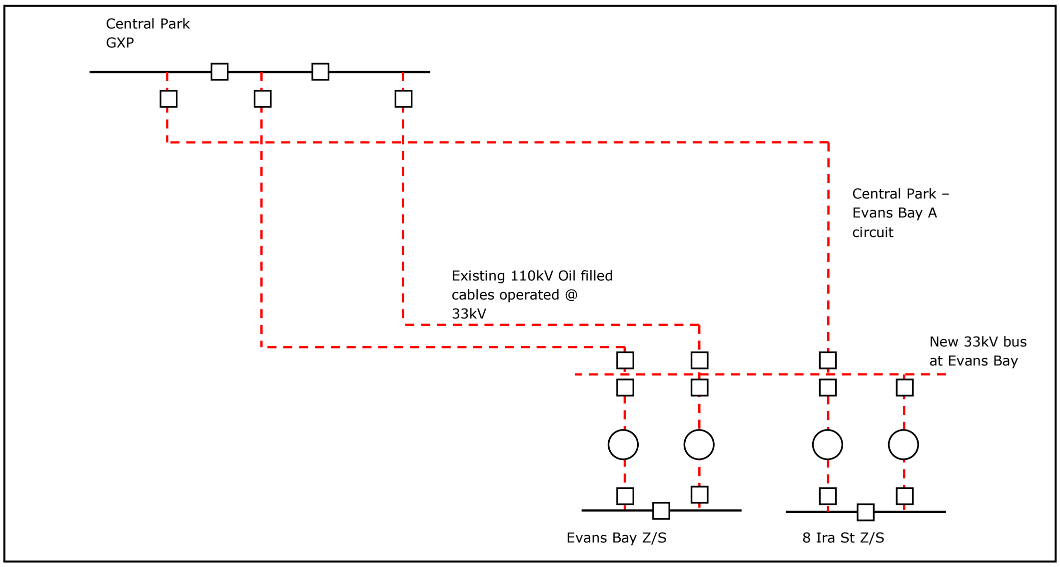


Figure C-4 Evans Bay 33kV Bus

There is sufficient space within the Evans Bay substation property for the establishment of a 33kV switchroom with a 33kV GIS bus consisting of six circuit breakers. Alternatively it may be possible to tee-off the subtransmission line at Evans Bay to the two zone substations.

Figure C-5 provides the estimated cost for these works.

Project Description	Cost ($K)	Year Investment Required
Evans Bay 33kV Bus **Ref 17-002**	4,500	2017

Figure C-5 Cost Estimate for Evans Bay 33kV Bus

These works will allow for the Evans Bay 1 subtransmission cable to be decommissioned.

The Evans Bay transformers are to be replaced by new units or the relocated units from Palm Grove.

Reinforce the Palm Grove Zone 1 Ring

It is expected that the Hospital will be expanding its facilities sometime after 2017. A new distribution substation will be required to provide a point of connection to these new facilities and provide diversity of supply to Wellington Hospital. These works provide the opportunity to provide greater inter-connectivity between Palm Grove, Frederick Street and Nairn Street while also alleviating loading on the Palm Grove 2/3/6 ring.

Figure C-6 shows the proposed reconfiguration of the Palm Grove 2/3/6 ring.

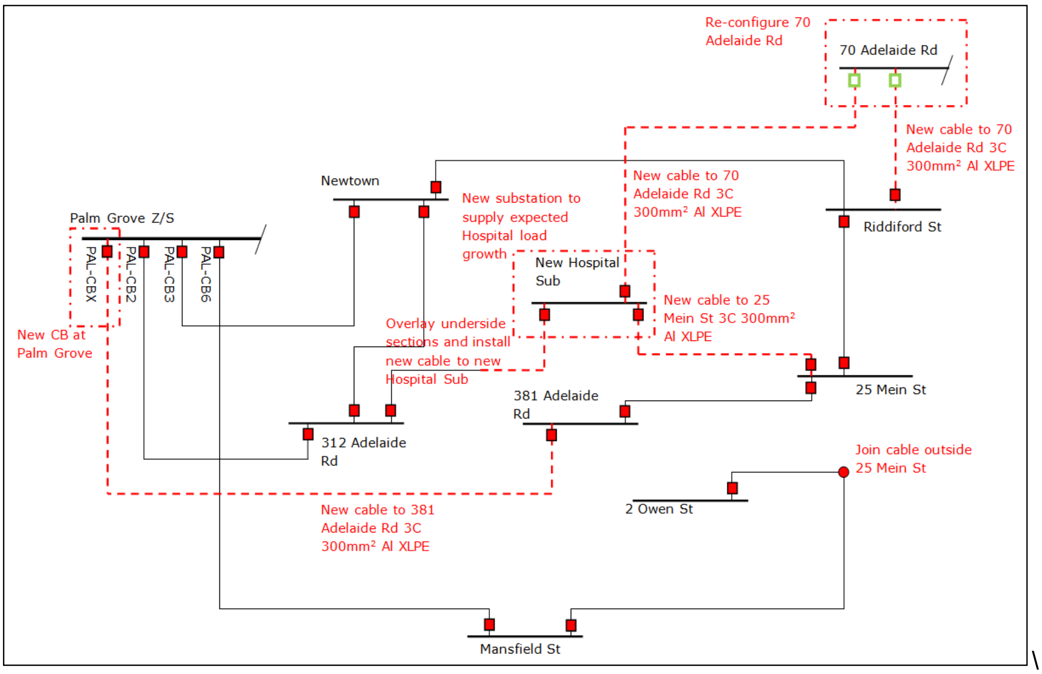


Figure C-6 Proposed Palm Grove Zone 1 Ring Reinforcement

The new Hospital distribution substation is to consist of three circuit breakers fitted with Solkor differential protection. A new LMVP circuit breaker complete with OC/EF (SEL 751A) and Solkor differential protection is to be installed to extend the Palm Grove 11kV bus.

A new feeder is to be installed between Palm Grove and 381 Adelaide Road. 312 Adelaide Road is to be connected with the new Hospital substation which will in reinforce supply to 25 Mein Street. Inter-connections shall be installed between 70 Adelaide Road and the new Hospital substation. These inter-connections provide sufficient capacity to allow for the entire load at the Wellington Hospital to be transferred to Frederick Street or Nairn Street via 70 Adelaide Road. Consequently, it is recommended that remote actuators and RTUs be fitted at all relevant substations to allow remote transfer switching.

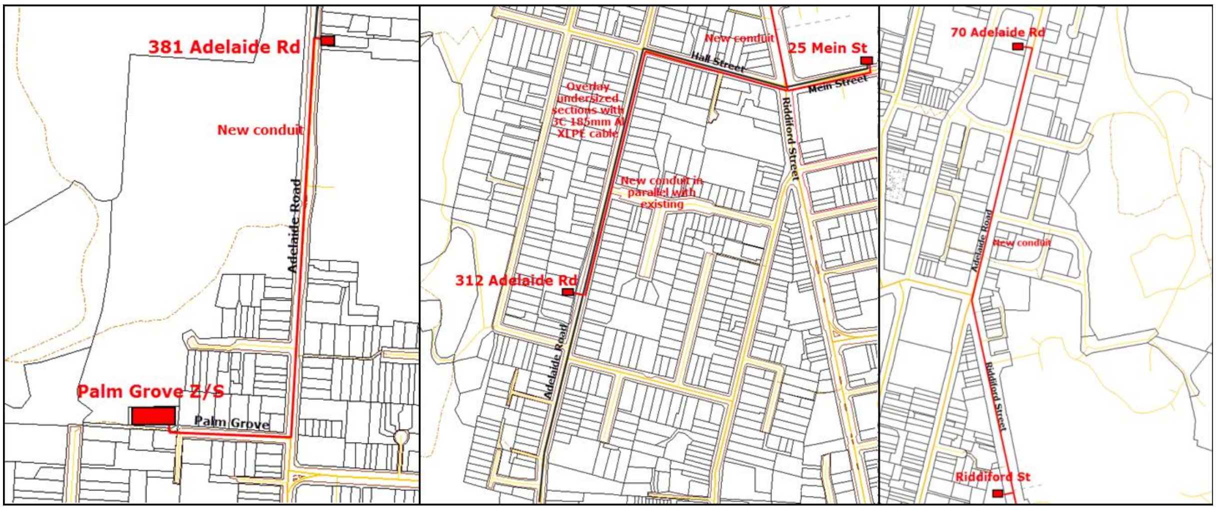


Figure C-7 Proposed Cable Route

Re-configuration of 70 Adelaide Road is also recommended to shift a portion of load from Frederick Street feeder 13/14 ring to Nairn Street. These works are not dependent on the network augmentations described at Palm Grove and can be performed when the loading on the Frederick Street feeder 13/14 ring breaches planning constraints.

A new RMU is to be installed at Adelaide Road to shift local supply transformers to the Nairn Street side of the bus. Alternatively, a new circuit breaker will need to be installed to extend the 70 Adelaide Rd bus. The feeders can be re-configured to provide spare breakers in preparation for termination of the new feeders to the new Hospital substation and Riddiford Street.

Figure C-8 provides the estimated cost for these works.

Project Description	Cost ($K)	Year Investment Required
Palm Grove Zone 1 Ring Reinforcement **Ref 19-003, 20-001**	4,400	2021-2023

Figure C-8 Cost estimate for Palm Grove Zone 1 Reinforcement

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, CentrePort and the central railway station. It has a summer peak and a typically commercial load profile.

A project was proposed in 2013 to install a new feeder from Moore Street zone substation to connect into the existing zone 2 ring for closed ring operation, and involved installation of a new circuit breaker on the T2 side of the 11kV bus at Moore Street and connection into an existing substation on Waterloo Quay.

The CentrePort reconfiguration project completed during 2014 alleviated the loading on Moore Street feeder 12 and 14 deferring this project. The Wellington Southern NDRP has identified load growth in the region that may require this project be enacted by 2019.

Load growth is high around the CentrePort 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, resulting in potential breaches of the planning criteria. As the demand increases over time, this problem will be compounded.

The approximate route of the new feeder will be along Thorndon Quay and Bunny Street to Customhouse Quay, terminating at 66 Waterloo Quay substation. This project will be coordinated with a planned customer driven project in the area to allow the costs of road opening, reinstatement and traffic management along the common route to be shared.

This new feeder will provide around 6MVA of capacity into Waterloo Quay and CentrePort area to allow connection of future load, and alleviate existing high loading.

Figure C-9 provides the estimated cost for this new feeder option.

Project Description	Cost ($K)	Year Investment Required
New Moore Street Feeder **Ref 18-003**	1,800	2019

Figure C-9 Cost Estimate for New Feeder into Waterloo Quay

Remote Distribution Switching

There is potential for efficiencies to be introduced to subtransmission and distribution level supply reliability through further deployment of remote switching.

In contrast to installing N-1 capacity, a more cost effective solution may be to utilise existing distribution level capacity. This can be achieved by identifying network critical distribution switching points and implementing a programme of refurbishment at these sites. Refurbishment will include the following works:

- Installation of communications infrastructure, including RTUs and communications links if necessary;
- Retrofit or replacement of distribution switchgear to provide facilities for remote actuation;
- Metering and telemetry of switch states, analogues etc. available via SCADA communications; and
- Installation of fault passage indication with remote indication.

Network critical switch points are defined as:

- RMUs with load break isolators supplying multiple feeder connections to adjacent feeders or zones; and

- Distribution switchboards with fault interrupting circuit breakers and protection relays to provide fault detection and clearing downstream from the zone substation.

For instance, at Frederick Street, loss of a radial feeder during peak demand would require a number of open points be manually switched to restore load. If the open points were remote actuated, either through automation or by an operator in the Network Control Room, the consumer impact of the out of service bus would be reduced. Supply could be restored as rapidly as switch states could be altered.

Figure C-10 shows a simplified overview of the proposed architecture.

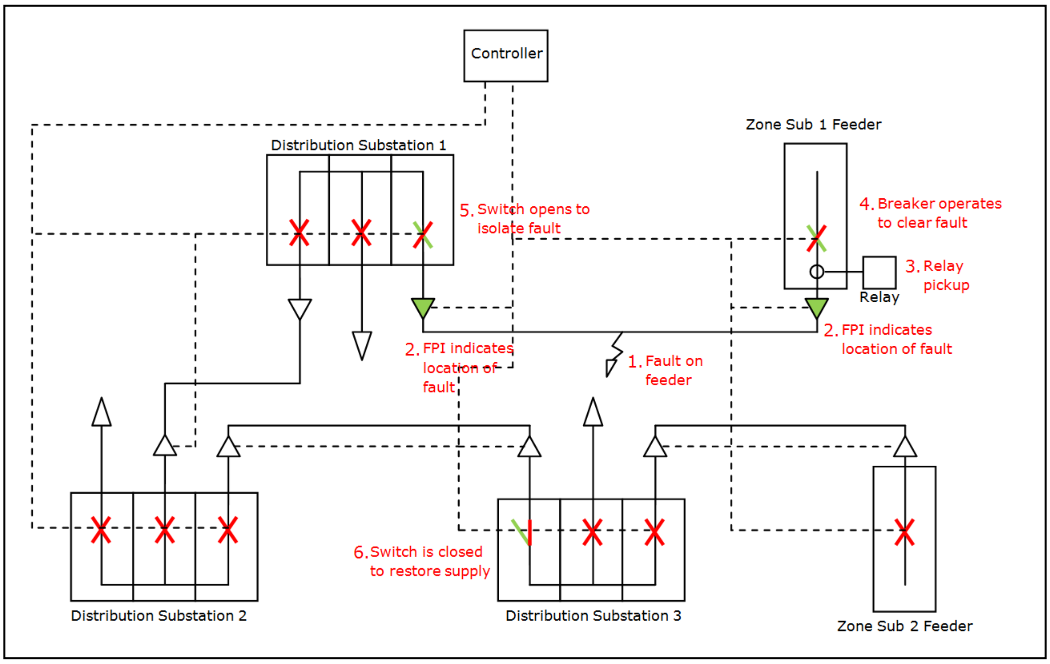


Figure C-10 Distribution Level Remote Switching

Further investigation of key sites and interconnections between zones will be required, however a high level investigation shows that approximately 65 sites would benefit from refurbishment with automation capability and will be integrated with asset renewal programmes.

Automated Bus-tie Changeover Scheme

Zone substations within the Wellington CBD (supplied from Central Park or Wilton GXPs) are normally operated with the bus tie open to restrict fault levels downstream. The result of a subtransmission fault is a loss of supply to approximately half of the customers supplied from the zone substation. The typical response once confirming a subtransmission trip is for the operator to close in the bus-tie such that the entire zone substation is supplied from one subtransmission circuit.

An automated change-over scheme has been designed and bench tested utilising an SEL751 relay which, following sufficient confirmation of the cause of fault and state of the network, can improve the speed of response to minimise the duration of interruption experienced by consumers. This scheme will be implemented at Frederick Street due to the high customer count and criticality of load supplied in 2016.

The total cost of these works is shown in Figure C-11.

Project Description	Cost ($K)	Year Investment Required
Frederick Street Bus-tie changeover scheme **Ref 16-001**	73	2016

Figure C-11 Frederick Street Bus-tie Changeover Scheme

Implementation at Frederick Street will act as a pilot project and proof of concept after which the expectation is that it will be installed at all zone substations operated with an open bus-tie to restrict fault levels. An implementation programme is to be developed staged over the next three years. The likely total cost of the programme is shown in Figure C-12.

Project Description	Cost ($K)	Year Investment Required
Bus-tie changeover implementation (3-4 sites per year) **Ref 17-003, 18-005, 19-004**	300	Annually on from 2017

Figure C-12 Bus-tie Changeover Scheme Programme

Fault Levels at CBD Zone Substations

All CBD[39] zone substations are operated with a split 11kV bus due to the high fault levels. 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.

There are a number of 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 switchgear at zone substations and downstream sites, to allow closed 11kV bus operation. To achieve this, a higher number of distribution switches would need to be replaced and given the high cost of this option is not considered viable in the short term. It may become possible over time as older switchgear is progressively replaced for other reasons.

High Impedance Zone Transformers

To reduce the fault level below the standard distribution equipment rating of 13kA, this option requires replacement of transformers with high winding impedance at CBD zone substations. CBD transformers are currently around 10-12% impedance, whereas 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 be replaced within the planning period. The benefit of this option is no additional equipment would be required

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

with no extra space requirements. The disadvantages are the high cost and very high losses in the zone transformers, as well as the costs associated with the accelerated depreciation of assets.

Current Limiting Reactors or Resistors

An option is 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 C-13 shows the typical arrangement of a bus tie reactor in a distribution system.

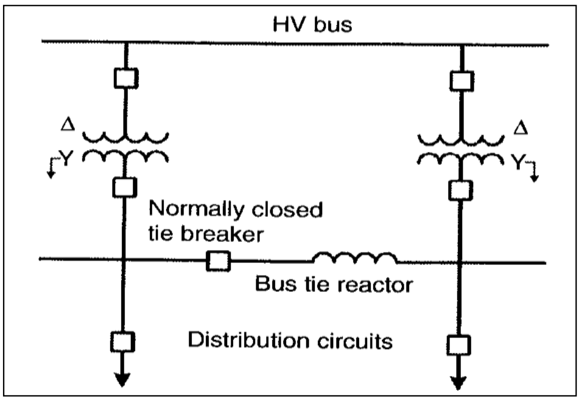


Figure C-13 Typical Bus Tie Reactor Arrangement

There is a physical limitation to the use of bus tie reactors in CBD substations as the 11kV switchgear is metal clad. 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 would be required to confirm the practicality of such a solution.

Further investigation would be required within the planning period to determine appropriate devices at the various CBD zone substations while allowing for fast acting protection clearing and adequate coordination with downstream devices.

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

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

The outcome of a detailed study may reveal that due to the age and condition of switchgear in the affected network areas, replacement with higher rated (and internally arc contained) switchgear may be a better overall investment.

Figure C-14 provides a project cost estimate for bus fault level improvements (or mitigation through other means).

Project Description	Cost ($K)	Year Investment Required
CBD substation bus fault level improvements **Ref: 19-005, 20-004, 21-002, 22-002, 23-001**	850	Annually from 2019 onwards

Figure C-14 Cost Estimate for Bus Fault Level Improvements

Install a New Substation in the Pauatahanui/Whitby Area

Site Designation

Provision of subtransmission supply to a new Pauatahanui zone substation is dependent on the location of the site. The most cost effective and feasible option would be installation within the bounds of the Pauatahanui GXP. There is sufficient room within this site for 33kV and 11kV switchboard.

Figure C-15 Proposed Pauatahanui Z/S site

Wellington Electricity will further investigate the feasibility and cost of purchase of sufficient land at the Pauatahanui GXP for installation of a new zone substation building containing an 11kV switchroom.

Distribution Network Interconnectivity

11kV distribution network arrangement designed for the new zone substation is to alleviate a number of distribution level issues within the Northwestern area:

- Provide sufficient backfeed of load from Waitangirua and Mana/Plimmerton to reduce demand to within available N-1 capacity at these sites; and

- Alleviate distribution constraints on feeders supplying the Aotea and Whitby areas to cater for future growth.

Figure C-16 shows the required distribution links from the new zone substation to Waitangirua and Mana/Plimmerton to satisfy network planning requirements. Additional feeders can tie into Plimmerton feeders routed in close proximity to the proposed substation site.

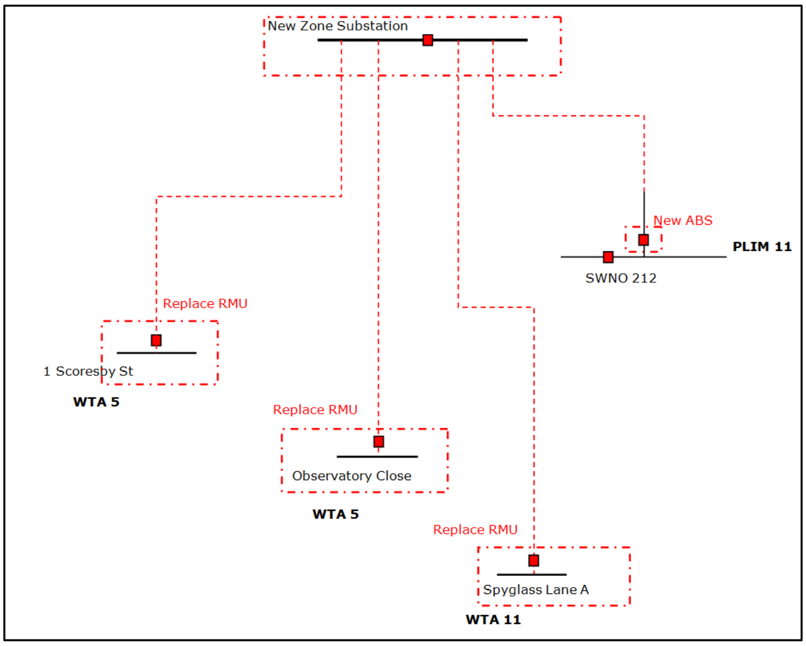


Figure C-16 Proposed Distribution Inter-connectivity

A significant number of open point changes will be required to optimise loading on feeders from Porirua, Waitangirua, Mana and Plimmerton zone substations.

Figure C-17 provides a high level cost estimate and time periods for the option of a new zone substation.

Project Description	Cost ($K)	Years Investment Required
Zone Substation Site: Establishment of a 2 x 24MVA zone substation **Ref 19-006**	2,500	2020-21
Distribution links to Waitangirua and Mana/Plimmerton **Ref 19-007**	4,720	2020-21
Total	**7,220**	

Figure C-17 Cost Estimate for Proposed new Pauatahanui Z/S

Subtransmission Supply

Provision of subtransmission supply to a new Pauatahanui zone substation is dependent on the location of the site. The most cost effective and feasible option would be installation within the bounds of the Pauatahanui GXP.

The Pauatahanui 110/33kV transformers are near capacity and at end of life. Supply of the new Pauatahanui zone substation from the 110kV bus at Pauatahanui GXP will effectively mitigate the capacity concerns at the Pauatahanui and Takapu Road GXPs.

The recommended option is to replace the existing Pauatahanui 110/33kV transformers with higher capacity three-winding units with a tertiary 11kV winding to supply a new 11kV bus. This is illustrated in Figure C-18.

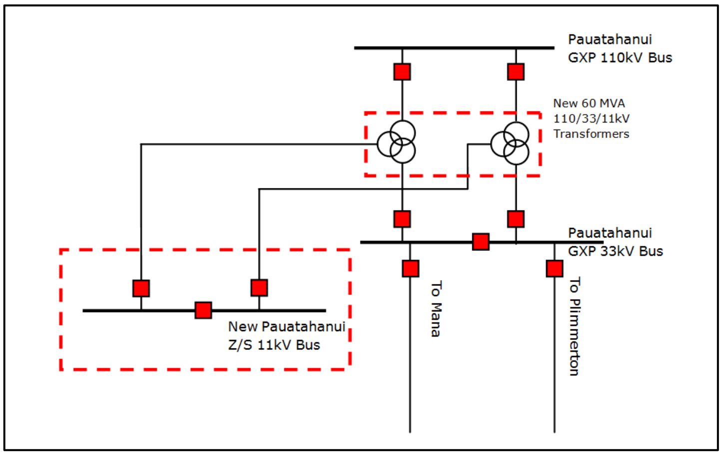


Figure C-18 Pauatahanui zone substation subtransmission supply

This option has the benefit of not requiring extension of the 110kV bus, however requires two high capacity three-winding transformer units to provide supply to both the 33kV and 11kV bus.

Reinforce the Porirua CBD ring network

Porirua City Council has published plans for re-vitalisation of the Porirua city centre, involving a new stream side plaza, re-development of the Porirua Civic precinct and a number of other initiatives. The expected load growth from these initiatives is expected to exceed planning criteria of the two feeder mesh distribution ring currently feeding the Porirua CBD.

Two projects have been planned for reinforcement of the Porirua CBD ring:

- Increase the meshing of the ring by installing a new cable between 17 Parumoana Street and 14 Parumoana Street;
- Install a new circuit breaker at Porirua zone substation and install a new feeder to 17 Parumoana Street.

The project to increase the meshing of the Porirua CBD ring will be initiated to increase capacity in the event a customer request for connection exceeds the applicable planning criteria. It is expected that these works will be required by 2018 and will complement the more long term solution of introducing a new feeder.

Installation of a new circuit breaker and feeder to the Porirua CBD ring is to further increase capacity and security of supply and is expected to be required by 2020, dependent on potential magnitude and timing of the step change growth expected due to the Porirua city centre revitalisation initiative.

The end result of these two separate works is shown in the diagram in Figure C-19.

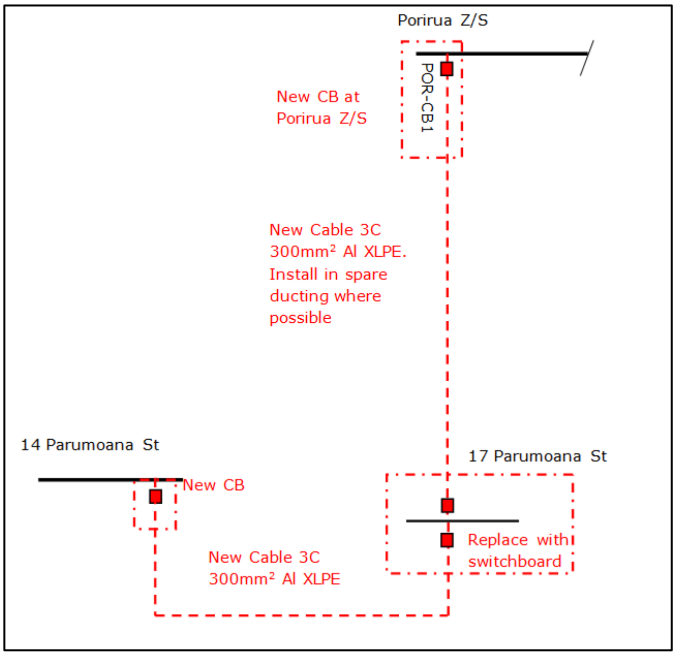


Figure C-19 Porirua CBD ring reinforcement

The potential cable route is shown in Figure C-20. Installation of a new feeder will be complicated by the requirement to cross the motorway overbridge. The availability of spare conduit capacity to simplify installation will be investigated further.

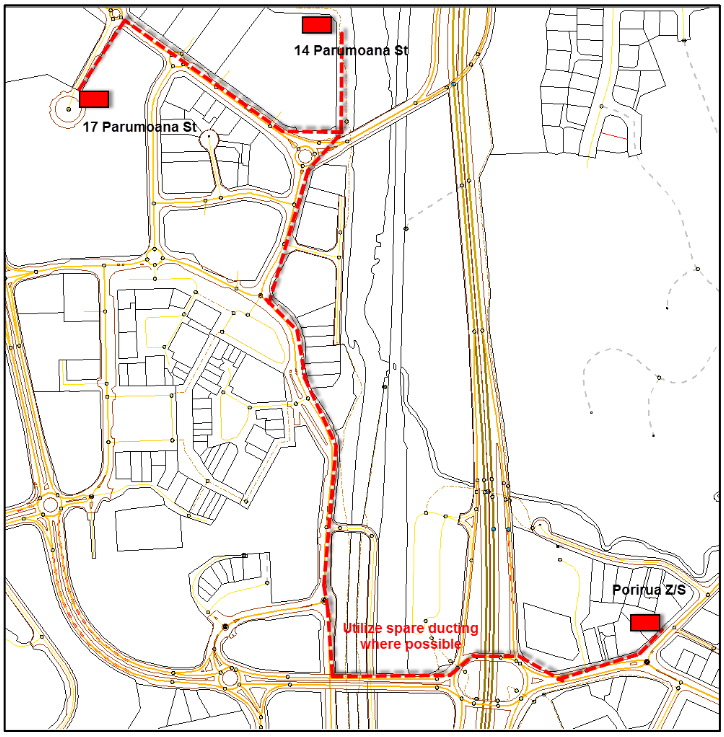


Figure C-20 Porirua CBD ring reinforcement cable route

The total cost of these works are shown in Figure C-21.

Project Description	Cost ($K)	Year Investment Required
Porirua CBD ring reinforcement Stage 1 – Meshing **Ref: 17-008**	240	2018
Porirua CBD ring reinforcement Stage 2 – New Feeder **Ref: 18-007**	880	2020
Total	1,120	

Figure C-21 Total cost of Porirua CBD ring reinforcement

Replace the Ngauranga Transformers

The existing 10MVA 33/11kV transformers at Ngauranga are to be replaced with 24MVA units. These transformers are in good condition but are the oldest in the network. New 24MVA transformers at Ngauranga will provide sufficient capacity to cater for long term growth in the Ngauranga area as shown in Figure C-22.

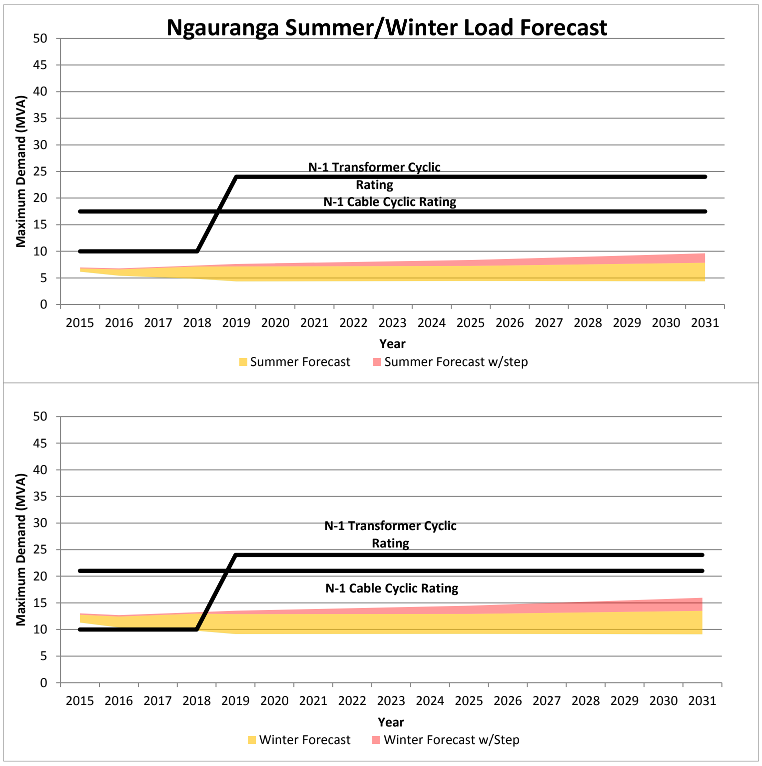


Figure C-22 Ngauranga Load Forecast following transformer replacement

Installation of new 24MVA transformers may require alteration of the existing transformer bay to accommodate the larger footprint and cooling requirements. Further investigation is required to determine feasibility and costing in 2016. A high level estimate of these works are shown in Figure C-23.

Project Description	Cost ($K)	Year Investment Required
Replacement of Ngauranga transformers with new 24MVA units **Ref: 19-008**	3,000	2020

Figure C-23 Total cost of Ngauranga transformer replacement

Takapu Road Subtransmission Protection Replacement

During 2015, Transpower completed works to convert the existing 33kV outdoor bus to an indoor GIS bus. Following these works, Wellington Electricity began execution of a staged programme to replace the aging protection devices on the subtransmission circuits supplied from Takapu Road.

The first stage, replacement of the protection relays on the circuits supplying Waitangirua, is currently in progress and due for completion in early 2016. Subsequent stages of the programme are as follows:

- Takapu Road Communications Link – Stage 1: To facilitate protection communications between Ngauranga, Tawa and Kenepuru zone substations to Takapu Road via leased fibre and copper pilots. Enabling works to facilitate this link should be completed by Q2 2016;

- Ngauranga subtransmission protection replacement: Replacement of the protection relays on the Ngauranga circuits. These works are dependent on the Takapu Road Communications Link – Stage 1 works and are planned for execution in Q3 2016. It will also be necessary to replace the RTU at Ngauranga;
- Tawa and Kenepuru subtransmission protection replacement: Replacement of the protection relays on the Tawa and Kenepuru circuits. Due to the tee-ed configuration of the subtransmission circuits supplying Tawa and Kenepuru, replacement of protection relays on these circuits is to be executed as a single project by Q4 2016. It will also be necessary to replace the RTUs at Tawa and Kenepuru;

These projects have been budgeted for in the 2016 spend plan.

Works required at Johnsonville and Porirua are required in 2017/18 and will be investigated further during 2016. These works include:

- Takapu Road Communications Link – Stage 2: To facilitate protection communications between Johnsonville and Takapu Road. Provision of communications links to this site are complicated by the location and distance from fibre corridors owned by the chosen fibre provider. An indicative estimate of $900,000 has been provided to facilitate Stage 2. Further investigation is required to determine the most economic option. Implementation will be required by Q2 2017.
- Johnsonville subtransmission protection replacement: Replacement of the protection relays on the Johnsonville circuits. These works are dependent on the Takapu Road Communications Link – Stage 2 works and are planned for execution in Q3 2017. During this time, it will also be necessary to replace the RTU at Johnsonville.
- Porirua subtransmission protection replacement: Replacement of the protection relays on the Porirua circuits. These works are planned for execution in 2018/19.

Takapu Road Communications Link – Stage 1

Due to age and risk, replacement of protection relays and RTUs on the Ngauranga, Tawa and Kenepuru subtransmission circuits has been prioritised for 2016. To facilitate these replacement projects, a protection and SCADA communications link is required. The existing copper pilot infrastructure installed between Takapu Road, Tawa, Kenepuru and Ngauranga is in poor condition and will not support protection communications between modern numerical differential relays.

To this end, Wellington Electricity will lease sufficient dark fibre pairs from a fibre service provider to facilitate protection and SCADA communications between Ngauranga, Tawa and Kenepuru. The existing pilot links between Kenepuru and Takapu Road are in relatively good condition, however repairs will be required to ensure compatibility with the new Siemens SIPROTEC5 relays providing differential protection. This link will eventually be replaced by a new fibre link between Kenepuru and Takapu Road, installed in conjunction with the NZTA Transmission Gully project.

The total cost of these works are shown in Figure C-24.

Project Description	Cost ($K)	Year Investment Required
Takapu Road Communications Link – Stage 1 **Ref: 15-003**	400	2016

Figure C-24 Total Cost of Waitangirua Subtransmission Protection Replacement

Ngauranga Subtransmission Protection Replacement

Ngauranga Zone Substation is fed from a common 33kV bus at Takapu Road via transformers TA and TB. Ngauranga is an atypical arrangement for the Wellington Electricity Network, in that 33kV circuit breakers are installed upstream of the transformers.

The subtransmission protection includes differential protection with a requirement for pilot supervision to be provided by the relays. This is currently not available with the existing Ngauranga subtransmission protection scheme.

New Siemens 7SD82 line differential and 7UT85 transformer differential numerical relays are to be installed at Ngauranga and Takapu Road respectively, to act as the primary protection on the subtransmission circuits. These new relays will provide separate line and transformer differential protection, offer pilot monitoring and supervision as well as advanced functionality including distance to fault measurement and fault recording. The existing Reyrolle Duobias relays and NVD scheme at Ngauranga are to be decommissioned.

The project is to occur in Q3 2016 following the completion of the Takapu Road Protection and Communication Link – Stage 1.

The estimated cost of these works are shown in Figure C-25.

Project Description	Cost ($K)	Year Investment Required
Ngauranga subtransmission protection replacement **Ref: 16-002**	352	2016

Figure C-25 Cost Estimate for Ngauranga Subtransmission Protection Replacement

Along with the communications upgrade, the old RTU at Ngauranga will be replaced to easily facilitate IP communications as part of the ongoing RTU replacement programme at an additional cost of $295,500

Tawa & Kenepuru Subtransmission Protection Replacement

The Tawa zone substation consists of a sectionalised bus section arrangement supplied by subtransmission circuits from Takapu Road GXP. The bus-tie between bus sections is typically operated closed to improve reliability of supply. Tawa zone substation supplies the mixed residential and commercial load in Tawa. The subtransmission circuits supplying Tawa are one branch of a tee-ed arrangement which also feeds Kenepuru zone substation. Two subtransmission circuits, consisting of Butterfly aerial conductors, are tee-ed off 700m out from Takapu Road.

The Kenepuru zone substation is identically configured. Kenepuru zone substation supplies the mostly residential areas of Kenepuru and industrial areas in Porirua.

The Takapu Road to Tawa subtransmission circuits has a tee-off connection to Kenepuru. These circuits are protected by a three-terminal electromechanical line differential scheme installed approximately 50 years ago, which operates in a similar fashion to Solkor cable differential relays.

The existing protection on the subtransmission feeders to Tawa and Kenepuru Zone substations are at an advanced age and have previously mal-operated. Spurious tripping or mal-operation of the existing differential protection relays has the potential to compromise supply to 7692 customers.

To mitigate the risk of failure of the Tawa and Kenepuru subtransmission protection relays, it is recommended that the existing electromechanical relays be replaced with new Siemens SIPROTEC5 numerical differential relays. The Takapu Road Communications Link – Stage 1 will facilitate protection communications between Tawa, Kenepuru and Takapu Road.

The estimated cost of these works is shown in Figure C-26.

Project Description	Cost ($K)	Year Investment Required
Tawa and Kenepuru subtransmission protection replacement **Ref: 16-004**	610	2016

Figure C-26 Cost Estimate for Tawa & Kenepuru Subtransmission Protection Replacement

Along with the communications upgrade, the old RTUs at Tawa & Kenepuru will be replaced to easily facilitate IP communications as part of the ongoing RTU replacement programme (discussed in Section 6) at an additional cost of $595,700.

Tawa and Kenepuru Sectionaliser Scheme

Due to the current configuration of the Tawa/Kenepuru tee-ed subtransmission cable arrangement, a three-terminal differential protection scheme will clear a fault on the subtransmission cables between Takapu Road, Tawa and Kenepuru by tripping the circuit breakers at the remote ends of the faulted circuit. This results in both Tawa and Kenepuru being reduced to supply from a single circuit or at N security.

The worst case scenario is for a planned/unplanned outage at Tawa and a fault on the in-service Tawa/Kenepuru circuit. This would result in a lengthy loss of supply to Tawa until backfeed switching can be implemented. Reduction of the duration of the fault can be achieved by installing a sectionalising scheme to provide indication and isolation of the faulted Tawa circuit, allowing for Kenepuru to be restored to N-1 subtransmission capacity. This allows significantly more load to be backfed from Kenepuru, minimising manual switching requirements and consequently the duration of the outage.

Installation of a sectionalising scheme will involve automating the linkages at the tee-off point, between Takapu Road and Tawa and Takapu Road and Kenepuru. The existing linkages are provided by manually operated knife links. New relay operated gas switches will be installed to replace perform this function with switch state indication provided to SCADA via radio or GPRS.

The estimated cost of these works is shown in Figure C-27.

Project Description	Cost ($K)	Year Investment Required
Tawa and Kenepuru sectionaliser scheme **Ref: 17-005**	300	2017

Figure C-27 Cost Estimate for Tawa & Kenepuru Sectionaliser Scheme

Appendix D Information Schedules

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		5,724	6,317	7,476	7,193	7,155	7,842	8,729	9,771	10,529	11,053	11,274
11	System growth		504	1,284	5,011	5,718	8,270	8,549	6,828	6,415	4,315	2,220	1,115
12	Asset replacement and renewal		19,383	23,031	20,858	20,568	19,474	19,548	22,618	24,731	27,535	30,892	29,040
13	Asset relocations		1,336	1,222	971	1,037	1,135	1,226	1,342	1,481	1,575	1,629	1,661
14	Reliability, safety and environment:												
15	Quality of supply		1,005	1,652	1,282	1,380	934	1,137	1,014	1,056	1,128	1,158	1,341
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		121	1,260	1,363	1,208	1,100	1,317	1,450	1,535	-	-	-
18	**Total reliability, safety and environment**		1,126	2,912	2,645	2,587	2,034	2,454	2,464	2,590	1,128	1,158	1,341
19	**Expenditure on network assets**		28,074	34,766	36,960	37,103	38,068	39,619	41,981	44,988	45,082	46,953	44,432
20	Expenditure on non-network assets		1,748	1,533	1,342	1,374	1,185	1,232	1,282	1,334	1,388	1,444	1,502
21	**Expenditure on assets**		29,822	36,299	38,302	38,477	39,253	40,851	43,263	46,322	46,470	48,397	45,935
22													
23	*plus* Cost of financing		201	244	258	259	264	275	290	306	313	325	309
24	*less* Value of capital contributions		4,879	5,202	5,828	5,678	5,720	6,257	6,949	7,763	8,351	8,751	8,926
25	*plus* Value of vested assets		-	-	-	-	-	-	-	-	-	-	-
26													
27	**Capital expenditure forecast**		25,143	31,342	32,731	33,058	33,796	34,869	36,604	38,865	38,431	39,971	37,318
28													
29	Assets commissioned		24,023	31,342	32,731	33,058	33,796	34,869	36,492	38,119	38,431	39,971	37,318
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
32			**$000 (in constant prices)**										
33	Consumer connection		5,724	6,236	7,186	6,778	6,610	7,103	7,751	8,506	8,986	9,249	9,249
34	System growth		504	1,268	4,816	5,388	7,640	7,743	6,063	5,585	3,683	1,858	915
35	Asset replacement and renewal		19,383	22,735	20,048	19,382	17,991	17,705	20,084	21,530	23,501	25,849	23,823
36	Asset relocations		1,336	1,206	933	977	1,049	1,110	1,192	1,289	1,344	1,363	1,363
37	Reliability, safety and environment:												
38	Quality of supply		1,005	1,631	1,232	1,300	863	1,030	900	919	963	969	1,100
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		121	1,244	1,310	1,138	1,016	1,193	1,288	1,336	-	-	-
41	**Total reliability, safety and environment**		1,126	2,875	2,542	2,438	1,879	2,223	2,188	2,255	963	969	1,100
42	**Expenditure on network assets**		28,074	34,320	35,525	34,963	35,169	35,884	37,278	39,165	38,477	39,288	36,450
43	Expenditure on non-network assets		1,748	1,513	1,290	1,295	1,094	1,116	1,139	1,161	1,185	1,208	1,232
44	**Expenditure on assets**		29,822	35,833	36,815	36,258	36,263	37,000	38,417	40,326	39,662	40,496	37,682
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												
50													

	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 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	81	290	415	545	739	978	1,265	1,543	1,804	2,025
System growth	-	16	195	330	630	806	765	830	632	362	200
Asset replacement and renewal	-	296	810	1,186	1,483	1,843	2,534	3,201	4,034	5,043	5,217
Asset relocations	-	16	38	60	86	116	150	192	231	266	298
Reliability, safety and environment:											
Quality of supply	-	21	50	80	71	107	114	137	165	189	241
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	16	53	70	84	124	162	199	-	-	-
Total reliability, safety and environment	-	37	103	149	155	231	276	335	165	189	241
Expenditure on network assets	-	446	1,435	2,140	2,899	3,735	4,703	5,823	6,605	7,665	7,982
Expenditure on non-network assets	-	20	52	79	90	116	144	173	203	236	270
Expenditure on assets	-	466	1,487	2,219	2,989	3,851	4,847	5,996	6,808	7,901	8,252

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Consumer types defined by EDB**	**$000 (in constant prices)**					
Substation	2,318	3,732	4,307	4,060	3,959	4,257
Subdivision	1,657	1,095	1,264	1,191	1,161	1,249
High Voltage Connection	-	120	139	131	127	137
Residential Customers	1,630	1,214	1,401	1,321	1,288	1,385
Public Lighting	119	75	75	75	75	75
**include additional rows if needed*						
Consumer connection expenditure	5,724	6,236	7,186	6,778	6,610	7,103
less Capital contributions funding consumer connection	3,950	4,303	4,958	4,677	4,561	4,901
Consumer connection less capital contributions	1,774	1,933	2,228	2,101	2,049	2,202

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	221	288	1,488	2,275	1,200	-
Zone substations	-	980	3,088	1,763	4,125	5,163
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	258	-	60	630	1,595	1,860
Distribution substations and transformers	25	-	-	-	-	-
Distribution switchgear	-	-	180	720	720	720
Other network assets	-	-	-	-	-	-
System growth expenditure	504	1,268	4,816	5,388	7,640	7,743
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	504	1,268	4,816	5,388	7,640	7,743

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		365	300	300	300	300	300
95	Zone substations		3,961	930	2,070	1,815	1,260	1,480
96	Distribution and LV lines		7,149	8,485	7,250	6,495	6,182	6,000
97	Distribution and LV cables		1,914	1,115	1,255	1,294	1,190	1,644
98	Distribution substations and transformers		2,082	3,375	2,375	2,500	2,500	2,625
99	Distribution switchgear		3,660	4,617	4,465	3,890	3,525	3,150
100	Other network assets		252	3,913	2,333	3,088	3,034	2,506
101	**Asset replacement and renewal expenditure**		19,383	22,735	20,048	19,382	17,991	17,705
102	*less* Capital contributions funding asset replacement and renewal		-	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**		19,383	22,735	20,048	19,382	17,991	17,705
104								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
107	**11a(v):Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	Asset Relocations		1,336	1,206	933	977	1,049	1,110
110	[Description of material project or programme]		-	-	-	-	-	-
111	[Description of material project or programme]		-	-	-	-	-	-
112	[Description of material project or programme]		-	-	-	-	-	-
113	[Description of material project or programme]		-	-	-	-	-	-
114	**include additional rows if needed*							
115	All other project or programmes - asset relocations							
116	**Asset relocations expenditure**		1,336	1,206	933	977	1,049	1,110
117	*less* Capital contributions funding asset relocations		930	832	644	674	724	766
118	**Asset relocations less capital contributions**		407	374	289	303	325	344
119								

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
122	**11a(vi):Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Reliability Improvement Projects		1,005	1,631	1,232	1,300	863	1,030
125	[Description of material project or programme]		-	-	-	-	-	-
126	[Description of material project or programme]		-	-	-	-	-	-
127	[Description of material project or programme]		-	-	-	-	-	-
128	[Description of material project or programme]		-	-	-	-	-	-
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply							
131	**Quality of supply expenditure**		1,005	1,631	1,232	1,300	863	1,030
132	*less* Capital contributions funding quality of supply							
133	**Quality of supply less capital contributions**		1,005	1,631	1,232	1,300	863	1,030
134								

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Project or programme**	$000 (in constant prices)					
[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 projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
*Project or programme**	$000 (in constant prices)					
Seismic Strengthening	45	944	1,010	988	1,016	1,193
Strategic Resilience Projects	76	300	300	150	-	-
[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 projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	121	1,244	1,310	1,138	1,016	1,193
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	121	1,244	1,310	1,138	1,016	1,193

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Software	1,537	1,331	1,134	1,139	963	982
IT Infrastructure	211	182	155	156	132	134
[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 projects or programmes - routine expenditure	-	-	-	-	-	-
Routine expenditure	1,748	1,513	1,290	1,295	1,094	1,116
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 projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	1,748	1,513	1,290	1,295	1,094	1,116

Company Name: **Wellington Electricity**
AMP Planning Period: **1 April 2016 – 31 March 2026**

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 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	4,186	4,205	4,306	4,380	4,454	4,530	4,607	4,685	4,765	4,846	4,928
11	Vegetation management	1,431	1,444	1,490	1,527	1,565	1,604	1,644	1,685	1,727	1,770	1,814
12	Routine and corrective maintenance and inspection	6,742	7,561	7,673	7,879	8,072	8,280	8,511	8,765	9,046	9,363	9,842
13	Asset replacement and renewal	1,155	1,172	1,220	1,229	1,270	1,319	1,369	1,424	1,480	1,532	1,576
14	**Network Opex**	13,514	14,382	14,690	15,014	15,361	15,734	16,132	16,560	17,018	17,511	18,160
15	System operations and network support	4,344	4,407	4,529	4,624	4,720	4,817	4,914	5,016	5,119	5,223	5,328
16	Business support	11,712	11,882	11,756	12,004	12,253	12,505	12,756	13,021	13,288	13,556	13,830
17	**Non-network opex**	16,056	16,289	16,285	16,628	16,973	17,322	17,670	18,037	18,408	18,779	19,158
18	**Operational expenditure**	29,570	30,671	30,975	31,642	32,334	33,056	33,803	34,597	35,426	36,290	37,318

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 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	4,186	4,151	4,139	4,127	4,115	4,103	4,091	4,079	4,067	4,055	4,043
23	Vegetation management	1,431	1,425	1,432	1,439	1,446	1,453	1,460	1,467	1,474	1,481	1,488
24	Routine and corrective maintenance and inspection	6,742	7,464	7,375	7,424	7,457	7,500	7,558	7,630	7,721	7,834	8,074
25	Asset replacement and renewal	1,155	1,157	1,173	1,158	1,173	1,195	1,216	1,240	1,263	1,282	1,293
26	**Network Opex**	13,514	14,197	14,119	14,148	14,191	14,251	14,325	14,416	14,525	14,652	14,898
27	System operations and network support	4,344	4,350	4,353	4,358	4,361	4,363	4,364	4,367	4,369	4,370	4,371
28	Business support	11,712	11,729	11,300	11,311	11,320	11,326	11,327	11,335	11,341	11,343	11,345
29	**Non-network opex**	16,056	16,080	15,653	15,669	15,681	15,689	15,691	15,702	15,711	15,713	15,716
30	**Operational expenditure**	29,570	30,277	29,772	29,817	29,872	29,940	30,016	30,118	30,235	30,366	30,614
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	1,055	1,108	1,163	1,221	1,282	1,346	1,414	1,484	1,559	1,637	1,718

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 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	54	167	253	339	427	516	606	698	791	885
43	Vegetation management	-	19	58	88	119	151	184	218	253	289	326
44	Routine and corrective maintenance and inspection	-	97	298	454	615	781	954	1,134	1,325	1,528	1,768
45	Asset replacement and renewal	-	15	47	71	97	124	153	184	217	250	283
46	**Network Opex**	-	185	570	866	1,170	1,483	1,807	2,143	2,493	2,859	3,263
47	System operations and network support	-	57	176	267	359	454	551	649	750	853	957
48	Business support	-	152	457	692	933	1,179	1,429	1,685	1,947	2,213	2,485
49	**Non-network opex**	-	209	632	959	1,293	1,633	1,980	2,335	2,697	3,066	3,442
50	**Operational expenditure**	-	394	1,203	1,825	2,462	3,116	3,787	4,478	5,190	5,924	6,704

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref											
7					**Asset condition at start of planning period (percentage of units by grade)**						
8											
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.05%	1.05%	35.07%	61.89%	1.94%	3	1.30%
11	All	Overhead Line	Wood poles	No.	0.83%	13.60%	64.44%	17.75%	3.38%	3	15.73%
12	All	Overhead Line	Other pole types	No.						N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		5.72%	93.65%	0.63%		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			4.90%	95.10%		3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km		23.24%	76.76%			3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	2.25%	3.39%	94.36%			3	2.25%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km		28.98%	71.02%			3	-
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.			100.00%			4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.		100.00%				4	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.			50.00%	50.00%		3	-
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.		1.63%	61.04%	37.33%		3	3.54%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.						N/A	
35											

					Asset condition at start of planning period (percentage of units by grade)						
36											
37	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
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	7.69%	11.54%	80.77%			4	7.69%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.29%	16.77%	70.68%	12.26%		3	1.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km		29.69%	63.79%	6.52%		3	1.00%
42	HV	Distribution Line	SWER conductor	km						N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.01%	0.14%	34.71%	65.14%		3	-
44	HV	Distribution Cable	Distribution UG PILC	km	0.07%	5.93%	83.59%	10.41%		3	-
45	HV	Distribution Cable	Distribution Submarine Cable	km			100.00%			4	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	12.00%	16.00%	20.00%	52.00%		3	28.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	1.54%	4.09%	67.98%	26.39%		3	18.83%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4.00%	30.69%	37.24%	28.07%		3	4.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	4.09%	8.32%	60.29%	27.30%		3	4.09%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.21%	4.25%	58.29%	37.25%		3	4.46%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.06%	2.96%	45.94%	51.04%		3	3.02%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.44%	8.83%	58.59%	32.14%		3	3.00%
53	HV	Distribution Transformer	Voltage regulators	No.						N/A	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.15%	3.94%	68.24%	27.67%		3	3.00%
55	LV	LV Line	LV OH Conductor	km	0.22%	14.20%	79.12%	6.46%		2	1.00%
56	LV	LV Cable	LV UG Cable	km	1.10%	2.74%	65.74%	30.42%		2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.07%	9.08%	67.24%	23.61%		1	2.00%
58	LV	Connections	OH/UG consumer service connections	No.	0.00%	0.03%	96.19%	3.78%		1	1.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	4.02%	21.93%	47.22%	26.83%		3	10.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	16.86%	26.67%	14.51%	41.96%		3	10.00%
61	All	Capacitor Banks	Capacitors including controls	No.						N/A	
62	All	Load Control	Centralised plant	Lot			96.15%	3.85%		3	15.38%
63	All	Load Control	Relays	No.						N/A	
64	All	Civils	Cable Tunnels	km			100.00%			3	-

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**

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
8										
9	8 Ira St	18	24	N-1	9	75%	24	75%	No constraint within +5 years	
10	Brown Owl	15	23	N-1	7	65%	23	65%	No constraint within +5 years	
11	Evans Bay	14	24	N-1	11	58%	24	58%	No constraint within +5 years	
12	Frederick St	29	36	N-1	13	81%	36	81%	No constraint within +5 years	
13	Gracefield	11	23	N-1	12	48%	23	43%	No constraint within +5 years	
14	Hataitai	20	23	N-1	11	87%	23	87%	No constraint within +5 years	
15	Johnsonville	17	23	N-1	9	74%	23	74%	No constraint within +5 years	
16	Karori	18	24	N-1	7	75%	24	75%	No constraint within +5 years	
17	Kenepuru	12	23	N-1	9	52%	23	52%	No constraint within +5 years	
18	Korokoro	19	23	N-1	17	83%	23	78%	No constraint within +5 years	
19	Maidstone	15	22	N-1	12	68%	22	68%	No constraint within +5 years	
20	Mana-Plimmerton	20	16	N-1	12	125%	16	125%	Transformer	Constraint due to Mana/Plimmerton transformer capacity and upstream Pauatahanui 110/33kV transformer capacity is operationally managed
21	Moore St	25	30	N-1	14	83%	30	83%	No constraint within +5 years	
22	Naenae	15	23	N-1	11	65%	23	65%	No constraint within +5 years	
23	Nairn St	23	30	N-1	16	77%	30	80%	No constraint within +5 years	
24	Ngauranga	14	12	N-1	10	117%	24	58%	Transformer	Constraint due to Ngauranga transformer capacity, mitigated by replacing transformer within +5 years
25	Palm Grove	25	24	N-1	13	104%	30	83%	No constraint within +5 years	
26	Porirua	20	20	N-1	14	100%	20	100%	Subtransmission circuit	High demand growth expected in Porirua supply area, operationally managed until new zone substation built in Whitby/Pauatahanui
27	Seaview	16	22	N-1	12	73%	22	68%	No constraint within +5 years	
28	Tawa	15	16	N-1	13	94%	16	100%	Transformer	High load growth in Tawa/Grenada area
	The Terrace	27	36	N-1	21		36	75%	No constraint within +5 years	
	Trentam	14	23	N-1	10		23	65%	No constraint within +5 years	
	University	21	24	N-1	21		24	88%	No constraint within +5 years	
	Waikowhai	16	19	N-1	10		19	84%	No constraint within +5 years	
	Wainuiomata	17	20	N-1	3		20	80%	No constraint within +5 years	
	Waitangirua	15	16	N-1	11		16	94%	No constraint within +5 years	
	Waterloo	17	23	N-1	14		23	70%	No constraint within +5 years	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**

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

sch ref			Number of connections					
8	*Number of ICPs connected in year by consumer type*							
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
11	*Consumer types defined by EDB**							
12	Domestic		751	751	751	751	751	751
13	Large Commercial		14	14	14	14	14	14
14	Large Industrial		2	2	2	2	2	2
15	Medium Commercial		10	10	10	10	10	10
	Small Commercial		402	402	402	402	402	402
	Small Industrial		6	6	6	6	6	6
16	Unmetered		28	28	28	28	28	28
17	**Connections total**		1,213	1,213	1,213	1,213	1,213	1,213
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		268	200	200	200	200	200
21	Capacity of distributed generation installed in year (MVA)		1	1	1	1	1	1

22 12c(ii) System Demand

sch ref									
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
25		GXP demand		480	479	479	479	481	483
26	*plus*	Distributed generation output at HV and above		75	75	75	75	75	75
27		**Maximum coincident system demand**		555	554	554	554	556	558
28	*less*	Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**		555	554	554	554	556	558
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		2,245	2,220	2,208	2,208	2,208	2,208
32	*less*	Electricity exports to GXPs			-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation		271	271	271	271	271	271
34	*less*	Net electricity supplied to (from) other EDBs			-	-	-	-	-
35		**Electricity entering system for supply to ICPs**		2,516	2,491	2,479	2,479	2,479	2,479
36	*less*	Total energy delivered to ICPs		2,396	2,372	2,361	2,361	2,361	2,361
37		**Losses**		120	119	118	118	118	118
38									
39		**Load factor**		52%	51%	51%	51%	51%	51%
40		**Loss ratio**		4.8%	4.8%	4.8%	4.8%	4.8%	4.8%

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	2.9	5.3	5.3	5.3	5.3	5.3
12	Class C (unplanned interruptions on the network)	27.4	30.1	30.1	30.1	30.1	30.1
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.02	0.02	0.02	0.02	0.02	0.02
15	Class C (unplanned interruptions on the network)	0.55	0.53	0.53	0.53	0.53	0.53

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	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 consistent 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 conisders asset stategy. 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 organisation 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).

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

					Company Name	Wellington Electricity
					AMP Planning Period	1 April 2016 – 31 March 2026
					Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan is 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, 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 ofasset 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	WE's arrangements fully cover all the requirements for the efficient and cost-effective implementation of the asset management plan, and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.		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 stategies 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.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Accountability for asset management responsibility from CEO, through GM - Asset Management, and through functional 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. A long term strategic resource map relative to asset management organisational delivery requirements is to be developed.		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?	3	Significant controls are in place to manage the delivery of AM activities within the outsourced contractors, through integration of respective management systems.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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
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.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	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 needeed to functional policies, standards, processes and the asset management information system.		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 and standard key competency requirements. These are reviewed six monthly through performance reviews. Thse are also being reviewed with the intention of developing and AM competencies framework wtihin 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 and standard key competency requirements. These are reviewed six monthly through performance reviews. Thse are also being reviewed with the intention of developing and AM competencies framework wtihin 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.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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
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.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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. In addition, specific asset management information is communicated directly to employees and contractors via safety alerts, technical alerts, and network instructions.		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?	3	Various systems are in place for the management of asset management information and data. The primary record of asset information is GIS, with maintenance records being held in SAP-PM.		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 consistency 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.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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
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.

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Asset management processes were fully reviewed during development of the business case to implement SAP PM, ensuring that they meet Wellington Electricity's requirements.		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 risk controls 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.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Outputs from risk assessments are fed back into standards, procedures and training through the actions resulting from weekly risk review meetings.		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. The Regulatory Analyst 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

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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
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.

Company Name	**Wellington Electricity**	
AMP Planning Period	**1 April 2016 – 31 March 2026**	
Asset Management Standard Applied		

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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 asset management policies, procedures and processes in place which deal with the management of assets during the design to commissioning phases. 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.		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 general inspection plan in place with remedial actions derived around prioritisation of critical defects. Ongoing training is carried out to standardise the level of consistency across the inspection and condition assessment process, 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 Senior Management Team 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 peformance management. Gaps in data and data quality exist, however this is being addressed through a proactive audit 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	Wellington Electricity has procedures that clearly outline the roles and responsibilities for managing incident and emergency situations. The asset failure investigation standard describes the process and responsibilities for investigating asset-related failures.		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 2016 – 31 March 2026
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 2016 – 31 March 2026**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
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 programme is mature and targeted to areas of risk and quality delivery, there are some areas of the asset management system and process that are not covered within the current audit regime.		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 implemented and embedded. Continuous improvement processes are set out and include consideration of cost, risk, performance and condition for assets managed across the whole lifecycle 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 companies within the group and from within the industry in New Zealand.		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 2016 – 31 March 2026**
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

Network and Non-network capital expenditure:

The difference represents inflation and is as follows:
2017 (1.3%); 2018 to 2026 (2.0%).

The rates from 2017 to 2019 are based on publically available Reserve Bank of New Zealand Forecasts. The rates for the seven years thereafter are based on the midpoint of the RBNZ target inflation range.

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 inflation and is as follows:
2017 (1.3%); 2018 to 2026 (2.0%).

The rates from 2017 to 2019 are based on publically available Reserve Bank of New Zealand Forecasts. The rates for the seven years thereafter are based on the midpoint of the RBNZ target inflation range.

Appendix E Information Schedules

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	1
3.2 Details of the background and objectives of the **EDB**'s asset management and planning processes	3,5
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	2.1
3.3.2 states the corporate mission or vision as it relates to asset management	3.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB**	5.3
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	5.3 – 5.6
3.3.5 includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans	3.1 & 5.3
3.4 Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed	1.1
3.5 The date that it was approved by the **directors**	1.1
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	3.6.1
3.6.2 what these interests are	3.6.1
3.6.3 how these interests are accommodated in asset management practices	3.6.1
3.6.4 how conflicting interests are managed	3.6.2

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**	3.2.3
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured	3.2.4 & 3.2.5
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	3.2.5.2 & 5.5.1
3.8 All significant assumptions:	
3.8.1 quantified where possible	Appendix A
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including	Appendix A
3.8.3 a description of changes proposed where the information is not based on the **EDB**'s existing business	Appendix A
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information	Appendix A
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Appendix E
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	1.2.1 & 1.7 & Appendix A
3.10 An overview of asset management strategy and delivery	5.3 & 5.5
3.11 An overview of systems and information management data	8.1 & 8.4
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	8.3
3.13 A description of the processes used within the **EDB** for-	
3.13.1 managing routine asset inspections and **network** maintenance	6.4 & 6.5
3.13.2 planning and implementing **network** development projects	7

Information Disclosure Requirements 2012 clause	AMP section
3.13.3 measuring **network** performance.	4.2
3.14 An overview of asset management documentation, controls and review processes	5.6
3.15 An overview of communication and participation processes	3.6
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	Appendix A
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.	4 & 5.3.1 & 6 & 7.1
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.	3.4 3.4.1 – 3.4.3 3.5 3.4 & 7.2
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.	7.2.9 & 3.4.4 3.4 & 7.4 3.3 & 3.4 & 7.4 3.4 & 6.5.5 6.5.3 & 6.5.4 6.5.7.2 & 6.5.7.3

Information Disclosure Requirements 2012 clause	AMP section
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	3 & 7
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 & 6.0 6.1 6.5 6.5
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**.	6.5.1 6.5.2 6.5.3 6.5.4 6.5.5 & 6.5.6 6.5.2.3 & 6.5.6 6.5.7 6.5.8 6.5.9 N/A
Service Levels 5. The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	4

Information Disclosure Requirements 2012 clause	AMP section
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**.	4.2.2
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.	3.6 & 4.4 4.3 & 6.2 – 6.7
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 & 3.6.1
9. Targets should be compared to historic values where available to provide context and scale to the reader.	4
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.	1.2 & 4.2.2
<u>Network Development Planning</u> 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;	7.1
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;	7.1 & 7.2
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;	6.2 & 7.1.6
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.	6.2 & 7.1.6 6.2 & 7.1.6
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	7.1.7
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**.	7.1.9

Information Disclosure Requirements 2012 clause	AMP section
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.	5.4.1.2
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;	7.2
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;	7.2.9
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	7.4 – 7.6
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.	7.1.8
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;	7.4 – 7.6 &
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;	Appendix C
11.9.3 consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment.	" " "
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;	7.4 – 7.6 & Appendix C
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	7.4 – 7.6 & Appendix C
11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**.	7.4 – 7.6 & Appendix C

Information Disclosure Requirements 2012 clause	AMP section
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.	7.1.8.1
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.	7.1.7 7.4.3.1 /7.5.3.1 & 7.6.3.1
<u>Lifecycle Asset Management Planning (Maintenance and Renewal)</u> 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**.	6.2 & 6.3 6.4 6.5 6.5 6.7
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.	6.2 – 6.4 6.5.2.3 6.5 6.5 6.5 – 6.7 Yes

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.	8.1 – 8.6
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; 14.3 A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2; 14.4 Details of emergency response and contingency plans.	 5.2 5.8 5.2 & 5.8 & 5.9 5.9
15. AMPs must provide details of performance measurement, evaluation, and improvement, including— 15.1 A review of progress against plan, both physical and financial;	 Appendix B
15.2 An evaluation and comparison of actual service level performance against targeted performance;	4
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	5.7
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.	5.7
Capability to deliver 16. **AMPs** must describe the processes used by the **EDB** to ensure that- 16.1 The AMP is realistic and the objectives set out in the plan can be achieved; 16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	 1.7 3.2.4

Appendix F Glossary of Abbreviations

AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
AHI	Asset Health Indicator
AMP	Asset Management Plan
Capex	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
CCT	Covered Conductor Thick
CEO	Chief Executive Officer
CIC	Capital Investment Committee
CKI	Cheung Kong Infrastructure Holdings Limited
CPI	Consumer Price Index
CPP	Customised Price Path
CPRG	Constant Price Revenue Growth
Cu	Copper
DC	Direct Current
DDA	Default Distribution Agreement
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DPP	Default Price-quality Path
DSA	Detailed Seismic Assessment
DTS	Distributed Temperature Sensing
EDB	Electricity Distribution Business
EDO	Expulsion Drop-out Fuse
EEA	Electricity Engineers Association
ENMAC	Electricity Network Management and Control
ERP	Emergency Response Plan
EV	Electric Vehicle
FPI	Fault Passage Indicators
GWh	Gigawatt Hour
GIS	Geographical Information System
GXP	Grid Exit Point
HILP	High Impact Low Probability
HLR	High Level Request/Response
HSE	Health, Safety and Environmental
HV	High Voltage
ICP	Installation Control Point
IEEE	Institute of Electrical and Electronic Engineers
IISC	International Infrastructure Services Company (NZ Branch)
IEP	Initial Evaluation Procedure of Seismic Assessment
ISO	International Standards Organisation
km	Kilometre
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere

kW	Kilowatt
kWh	Kilowatt hour
LTI	Lost time injury
LTIFR	Lost time injuries per 1,000,000 hours worked
LV	Low Voltage
LVABC	Low Voltage Aerial Bundled Conductor
MAR	Maximum Allowable Revenue
MED	Major Event Day
MUoSA	Model Use of System Agreement
MW	Megawatt
MVA	Megavolt Ampere
NBS	New Building Standard
NCR	Network Control Room
NDP	Network Development Plan
NICAD	Nickel Cadmium Battery
NIWA	National Institute of Water and Atmospheric Research
NPV	Net Present Value
NZTA	New Zealand Transport Agency
OD-ID	Outdoor to Indoor conversion
ODV	Optimised Deprival Value/Valuation
O&M	Operating and Maintenance
OLTC	On Load Tap Changer
Opex	Operational Expenditure
PAHL	Power Asset Holdings Limited
PDC	Polarisation Depolarisation Current
PIAS	Paper Insulated Aluminium Sheath Cable
PILC	Paper Insulated Lead Cable
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PV	Photovoltaic Generation
PVC	Polyvinyl Chloride
RMU	Ring Main Unit
RTU	Remote Terminal Unit
RY	Regulatory Year (1 April – 31 March)
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
TNIFR	Total notifiable injuries per 1,000,000 hours worked
TPM	Transmission Pricing Methodology
UFB	Ultrafast Broadband
VRLA	Valve Regulated Lead Acid Battery
WCC	Wellington City Council
WELL	Wellington Electricity Lines Limited
W/S	Winter / Summer
XLPE	Cross Linked Polyethylene insulation

Appendix G Subtransmission Single Line Diagram