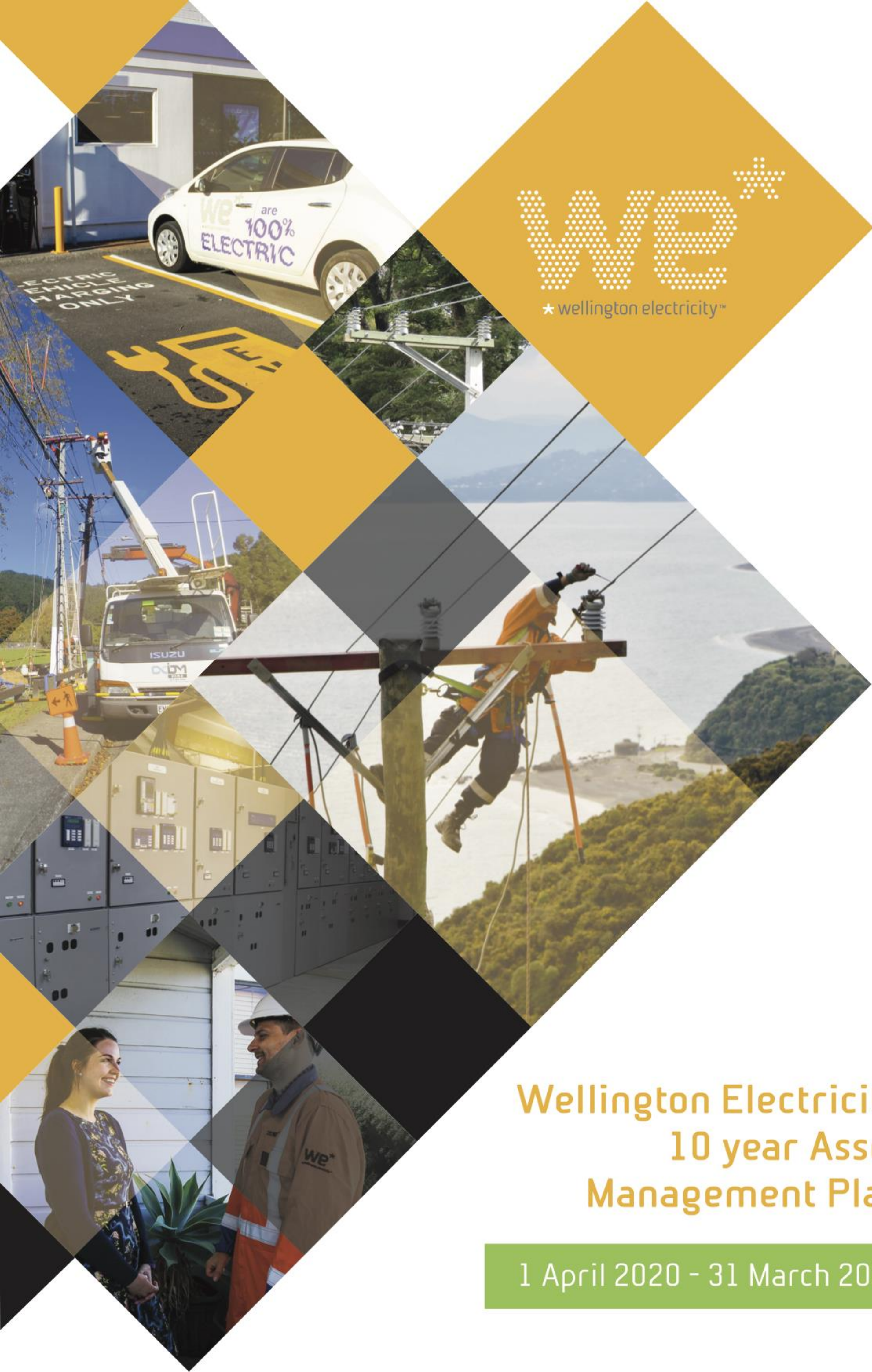

Wellington Electricity 10 year Asset Management Plan

1 April 2020 - 31 March 2030

Wellington Electricity

10 Year Asset Management Plan

1 April 2020 – 31 March 2030

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

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LIABILITY DISCLAIMER

Wellington Electricity Lines Limited (WELL) 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 2018).

Information, outcomes and statements in this version of the AMP are based on information available to WELL 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.

Neither WELL nor any other person involved in the preparation of this AMP will be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury, or damage arising directly or indirectly from any person relying on this AMP, to the extent permitted by law.

Any person wishing to use any information contained in this AMP should seek and take expert advice in relation to their own circumstances and rely on their own judgement and advice.

Statement from the Chief Executive Officer

Wellington Electricity (WELL) welcomes the opportunity to submit an updated Asset Management Plan (AMP) for the regulatory period 2020/21 to 2029/30. We confirm that this AMP has been prepared in accordance with the Commerce Commission's (the Commission) Electricity Distribution Information Disclosure Determination 2012 requirements.

This AMP has had a later release than previous plans due to the Commission allowing more time for Director Certification in recognition of the disruption the 23 March 2020 Level 4 lockdown has had on businesses and our community as we all do our share to fight the COVID-19 pandemic.

Our operations over the last 12 months have continued to focus on delivering high levels of safety, reliability and service to our customers. WELL continues to proactively engage with WorkSafe, the Commission and the Electricity Authority on improvements in safety performance, the price-quality path and market regulations so customers can continue to receive the long term benefits from sustainable investments made in electricity infrastructure.

Health and safety remains a positive driver for improved engagement with our field staff under an outsourced arrangement. The renewed field services agreement has adopted new work prioritisation and programming tools and seen the transition of low voltage (LV) network management return to the asset owner. This has provided tighter controls around LV work planning and a continued focus on LV work behaviours. As a lifeline utility we need to continue to provide our community with a safe, reliable and secure energy delivery system.

We continue to focus on improving safety behaviours and standards. Safety is an ongoing discipline and needs to be regularly supported. This is particularly relevant to maintaining wellness through the courage of more engaged conversations.

Through the EnergyMate programme, WELL has continued to work with consumers to understand their requirements and to tackle the "Energy Poverty" question alongside the Electricity Retailers' Association of New Zealand (ERANZ). This programme has highlighted where 50 Porirua homes first need assistance: improving housing stock ahead of energy efficiency or tariff adjustments.

While the business is currently under a quality investigation, we are pleased to deliver for a second year the improved reliability performance that allowed the network to operate one standard deviation less than the targeted interruption levels (SAIDI & SAIFI). This underlines the team effort across planning, real-time control and field implementation which makes this network one of the best performing in New Zealand, subject to a normal meteorological and seismological year. Valuable engagement is occurring with consumer groups on feeders experiencing vegetation outages. WELL's tree management practices are changing from the traditional notification process to a more consultative approach with tree owners.

We are 60% of the way through the Earthquake Readiness programme which was approved through a Customised Price Path (CPP) process in 2018. The programme provides funding to purchase spares and prepare critical systems to allow improved support to response and recovery from a major seismic event. The final year of the programme includes construction of data centres and mobile substations, and the completion of the seismic reinforcement of the remainder of 91 critical buildings. The AMP reports progress of this Earthquake Readiness programme and the future plans to be discussed with the Commission on how the Wellington Lifelines Regional Resilience Project is accommodated under Part 4, for the long term benefit of our customers.

We continue to invest in the network assets where they require replacement or maintenance to meet the required asset performance standards. Our maintenance management approach is prioritised based on asset health and asset criticality. This focuses expenditure on the highest ranked safety and reliability risk defects. These costs are expected to increase on the back of higher demand through consumer growth from subdivisions to meet a buoyant housing market, and the electrification of transport with 3,500 electric vehicles (EVs) now registered in our region.

The 2020 AMP updates our review of emerging technology and how this is expected to impact the network as consumers exercise their choices in adopting new products. Built from the 2019 AMP which socialised new technology areas, the 2020 AMP introduces some of the business plan changes and standards required to ensure that the network can remain secure in the changing environment. It also highlights the collaboration required through the supply chain so we can effectively integrate retail customers' needs while also supporting a more efficient network which is able to orchestrate a range of more complex demands.

Because of the flexibility required to accommodate the technological change, the current Default Price Path (DPP) (business as usual) approach is unlikely to provide the regulatory support needed. The alternative, big investment CPP approach, only works when there is clarity and certainty around the step change in investment needed. Regulatory frameworks do not appear to be developing fast enough to accommodate this change and unless we see initiatives in this area, the 0.1% innovation fund under DPP3 will be insufficient to fund the research and development required to efficiently integrate new technology, and the traditional asset investment approach will prevail. We encourage regulators to consider Ofgem's approach of managing uncertainty through a contestable innovation fund where Electricity Distribution Businesses bid and share successful ideas. Without this forward looking approach, we will be left with a backwards-looking toolset, inadequate to manage and support the pace of distributed energy resource (DER) adoption our customers will be embracing in the near future.

Turning the LV network into an active grid will require real time communication and monitoring to ensure that new technology can be used to support the network at a lower cost than building a bigger network. Retailers and Networks will need tools which consumers can use to propose and accept services, to commercialise their new technology investments to work with, rather than against, securing the connection to a high quality and responsive LV network. Without standards and coordination there is a risk that uncontrolled usage of new technologies will deteriorate the security and quality of supply from the LV network, negatively affecting all customers.

Unlocking the benefits of new technology at the LV level for customers, retailers and network operators is an important step change in collaboration and co-operation for our sector. Retailers will have opportunities to enable their customers to provide services to support network demand. This will maintain the standard of supply from the network system under two way power flows by balancing storage, generation and consumption. The EECA Low Emission Vehicle Contestable Fund is assisting a project to initially trial the management of domestic EV charging utilising night-time capacity headroom. In response to the Electricity Authority's request for greater cost reflectivity in network tariffs, WELL is delivering customers the choice of a residential time-of-use tariff. We have retained the electric vehicle and battery tariff from 2019 as an attractive option for charging EVs on the Wellington network during off-peak periods.

There may still be a need for large network reinforcement as the signalled shift away from fossil fuels will see consumers turn to the use of electricity in preference to gas. We have not factored this extra significant reinforcement investment into the 2020 plan as forecasts for reduced gas availability are beyond the 10 year planning horizon. It is however, part of our planning discussions going forward. We see there is immediacy in understanding consumer investment in DER, hence investment is being targeted at developing better coordination with customers and retailers at the boundaries between the LV network and the customers' supply. The additional investment required is to maintain a network which is capable to deliver on these new demands.

WELL is comfortable that the expenditure allowances for the current period will meet the investment needed for base network requirements. The additional allowances identified are needed to allow new technology to be fully integrated to enable services from consumers and retailers and to defer capacity investment, and for additional resiliency expenditure requested by customers.

Being a member of the CK Infrastructure Holdings Limited group allows WELL 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, WELL will continue to focus on the development of asset management strategies in parallel with the short to long term planning for the network for sustainable investment that delivers long term benefits for customers.

We welcome any comments or suggestions regarding this AMP.

Greg Skelton

Chief Executive Officer

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Section 1

Executive Summary

1 Executive Summary

The purpose of this Asset Management Plan (AMP) is to communicate Wellington Electricity Lines Limited's (WELL's) approach for the safe, reliable, cost effective and sustainable long-term supply of electricity. The AMP explains how electricity supply will be delivered at a quality and price expected by electricity customers connected to the Wellington network.

1.1 Term covered by the AMP

This AMP covers the 10-year period commencing 1 April 2020 through to 31 March 2030. It was approved by WELL's Board of Directors on 9 April 2020.

1.2 Changes from the 2019 AMP

The main changes in this AMP are:

- Network growth forecast: An update of the growth capital requirements to reflect forecast increases in connections and localised demand; and
- Network reliability: An update on network reliability management including an explanation of our reliability forecast models.

Appendix B provides further detail on the changes made since the 2019 AMP.

1.2.1 Network Growth Forecast

During 2019, a significant review was completed of future growth capital requirements in light of recent increases in new connections and localised increases in demand. This organic growth has eroded the capacity headroom in a number of areas, and as a result projects have been included in this AMP to create the required step change in network capacity. The Porirua zone substation rebuild and the construction of a new substation at Grenada are examples of projects that are required to increase capacity into the surrounding areas.

The network reinforcement projects will be implemented in parallel with WELL's demand management programmes: developing distributed energy resource (DER) solutions to directly manage demand and pricing signals to encourage off peak usage. Both are needed to ensure the Wellington network has the capacity to meet our customers' increasing energy demands.

1.2.2 Network Reliability

Wellington's electricity network is one of the most reliable in New Zealand due to the high proportion of underground cabling. However, the overhead network can be vulnerable to damage from storms and other external events. While large disruptions can occur and some interruption is expected, customers can reasonably expect to have supply returned without undue delay as their welfare and the region's economy will quickly suffer if the power stays off. For this reason, WELL is committed to providing customers with a reliable, cost-effective and secure electricity supply.

The reliability performance of the network in the 2019/20 year was good, following a similarly strong 2018/19 year result. However, WELL did exceed its quality targets in 2016/17 and 2017/18, which the Commerce Commission (the Commission) is currently investigating.

WELL is working positively with the Commission to answer questions and to highlight that the network components overall have generally performed better than the DPP2 reference period, and that the 2016/17 results reflect the impact from the Kaikoura earthquake. WELL has responded with additional controls to mitigate the outage causes that resulted in the breach, which it believes have been successful due to reliability performance in subsequent years.

This AMP also includes greater analysis using asset fleet survival curves to link forecast expenditure to asset failure rates in order to forecast and maintain reliability levels.

1.3 The Changing Environment

The environment in which WELL operates is changing. The changes include:

- The opportunities and threats from emerging technologies as customer needs and technology costs change;
- Government policy on decarbonisation of transport and process heat;
- Increased forecast demand driving investments in localised areas;
- The continued resiliency efforts in the Wellington Region to prepare for a major earthquake;
- The new default price path (DPP); and
- The effects of the Health and Safety at Work Act 2015 on business as usual activities.

These near term changes will impact WELL's operations going forward and require ongoing revision of investment plans and business models to ensure WELL can continue to provide safe, reliable, and cost-effective services. This AMP highlights some of the major foreseeable changes that are on the horizon and illustrates how WELL plans to position itself to manage these changes. Additionally, a change in government policy on gas exploration from 2050 will see the electrification of industrial heat for gas users. The impact of this policy change has not been included in this AMP. It will be factored into future forecasts once the energy demand impact of this change is better understood.

1.3.1 The Emerging Technology Market

This AMP is consistent with views of the Business New Zealand Energy Council who have highlighted three major themes for change in the energy industry being:

- Digitalisation;
- Decarbonisation; and
- Decentralisation.

These changes will have an effect on WELL as new technologies are increasingly adopted by customers. Although the potential benefit of new technology is great, there is a risk that uncontrolled usage of these technologies will cause large changes to traditional demand profiles including two way power flows. This may lead to large network reinforcement requirements to ensure that the network is capable to deliver on these demands.

An alternative approach, supported by WELL, is to develop a Distributed System Operator (DSO) platform which will provide signals to monitor and manage energy use, avoiding or delaying investment in building a larger traditional network. The platform allows services to be traded by retailers and aggregators within the constraints of the network to either alleviate congestion or maximise capacity availability from DER.

As well as working with industry and regulators to ensure these changes are implemented in the short term, WELL continues to learn from others and trial new technologies to prepare for the changes ahead. WELL believes this is a prudent and flexible approach to manage uncertainty associated with new and emerging technology and will avoid overbuild in the short term. This AMP includes a range of trials which will test the viability and effectiveness of using distributed energy resources to manage congestion on the network. Section 9 Emerging Technology, provides details of the trials programme. The results of the trials will be used to develop a business case for the full deployment of the distributed energy monitoring and management solution. The business case will be used to inform future iterations of the AMP.

This programme includes running an EV/battery charging trial managed in collaboration with industry participants which will help define services that can be valued and traded in order to defer network investment. This is not a completely new concept as hot water load shifting through ripple control has been in place for many decades and allows for less network investment and therefore lower costs to customers. WELL believes that this approach of leveraging DERs and applying a digital decentralised model will allow customers to play an active part in generation, demand and storage.

The investment in newer technologies and management tools could result in large scale benefits to customers and stakeholders. This investment does however come at a cost which is currently not part of WELL's DPP allowance. It is WELL's opinion that these allowances should be incentivised under the Commerce Act 1986, or through the application of mechanisms under Part 4 Clause 54Q.[1]

Initial industry changes to enable the introduction of disruptive technology include:

a. New technology standards: Introduce new standards for new technology, allowing integration at lower cost;

b. Mandatory notification: Require customers who want to install new technology to apply to their lines company (similar to the existing distributed generation rules). This will ensure that the installation of the new technology complies with the standards of the network for two way power flows, and minimise power quality impacts on other customers;

c. Congestion standards: Introduce standards on how congestion is defined and require network congestion to be disclosed;

d. Low voltage monitoring: Improve the monitoring of the LV network with high DER penetrations where current monitoring is inadequate and where changes are most likely to be felt;

[1] Clause 54Q states: *"The Commission must promote incentives, and must avoid imposing disincentives, for suppliers of electricity lines services to invest in energy efficiency and demand side management, and to reduce energy losses, when applying this Part in relation to electricity lines services."*

e. Management of distributed resources: Investigate and trial platforms that enables the management of distributed energy resources;

f. Support with efficient prices: Introduce efficient prices that reflect the benefits and encourage the use of disruptive technology;

g. Data streams from smart devices located behind the meter: Require LV data to be made available to the supply chain. This would improve Electricity Distribution Businesses (EDBs) visibility of the LV network, allowing them to manage demand effectively and to calculate efficient prices for services using disruptive technology; and

h. Available funding: Ensure that funding is available to develop and implement the new technology.

1.3.1.1 The Risk on Future Asset Recoveries

Although the stranded asset risks posed by new technologies may lead to underutilisation of assets for some EDBs,[2] WELL is of the opinion that this will generally not be the case in the Wellington region. WELL expects there to only be small sections of the network where underutilisation may be a risk to capital recoveries over the lifetime of assets, rather than for the majority of the network. The substitution of gas with electricity for home and commercial heat is expected to require further network development on a 10-20 year horizon as this government-led decarbonisation strategy begins to bed in. WELL's approach to move towards development of DSO tools, helping provide retailers and their customers with a DER platform to manage emerging technologies, will mean that the risk to potential underutilisation of assets will be managed and controlled.

This is considered a more prudent solution for customers in the Wellington region, rather than applying for accelerated depreciation recoveries, as it improves the utilisation of the existing network and will keep prices low.

1.3.2 The Focus on Resiliency Efforts

As a lifeline utility in accordance with the Civil Defence and Emergency Management Act 2002 (CDEM Act), WELL must ensure that it is able to function to the fullest possible extent, even though this may be at a reduced capacity, during and after an emergency. This can include one-off events such as storms and earthquakes. A concern for WELL is that the existing avenue of funding, via either the DPP allowances or the expensive Customised Price Path (CPP) process better suited to very large investments, does not cater for resilience programmes. This was shown by WELL's unique Streamlined CPP (SCPP) application which needed to be supported by a Government Policy Statement to address earthquake readiness following the 2016 Kaikoura earthquake.

The total approved SCPP allowance is $31.24 million over the three year period from April 2018 to March 2021. The delivery of the SCPP has been broken up into five work streams and, as explained in Section 11, is on track for completion by 2021. The progress of each work stream is detailed in Table 1-1.

[2] And may require those EDBs to seek accelerated capital recoveries.

Work Stream	2018/19 Total	2019/20 Total	2020/21 Total	Total
Critical Spares	13%	19%	3%	35%
Building Strengthening	12%	15%	7%	34%
Mobile Subs x 2			13%	13%
Data Centres x 3			13%	13%
Radio and Phones		5%		5%
Totals Accumulated	**25%**	**64%**	**100%**	**100%**

Table 1-1 SCPP Progress by Work Stream

Continuing in parallel to the earthquake readiness SCPP, WELL has investigated future resilience initiatives with the Wellington Lifelines Group to improve the network's ability to withstand High Impact Low Probability (HILP) events. This includes:

- The evaluation of solutions with Transpower on the options to manage the single point of supply risk of the Transpower Central Park grid exit point in Brooklyn; and
- Replacement of high risk 33kV fluid filled cables being brought forward to allow faster restoration of power following a major earthquake.[3]

The expenditure for both items is not included in the cost forecasts in this AMP as these would first need extensive consultation with customers in the Wellington region because the programmes would require a price increase to fund them.

1.3.3 The New Default Price Path

WELL moved from being regulated on a DPP to a CPP in March 2018 when the Commission approved WELL's earthquake readiness expenditure proposal, and was moved from a Price Cap to a Revenue Cap under the CPP Determination.

DPP3 starts on 1 April 2020 and WELL will move onto this when its CPP expires on 1 April 2021. WELL regularly reviews which regulatory model is most appropriate, balancing the low cost simplicity of a DPP against the ability of funding large capital programmes under the CPP.

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

The HSW Act introduced significant reform in workplace health and safety behaviour. This reinforced the ongoing requirement for due diligence and governance from Board level down and across all parties involved in the supply chain. Under the HSW Act, there are clearer obligations for the Principal (e.g. WELL) to ensure that those contracted to do its work (e.g. Northpower, Treescape etc.), and their subcontractors are free from harm. WELL is responsible for ensuring that risks are considered and controls are in place for

[3] WELL also met with the Commission in early 2020 to discuss 33kV subtransmission assets. The Commission was interested in why fluid-filled cable leakage charts were not presented the 2019 AMP. These had been removed in an attempt to simplify the AMP, but have been added back to this AMP because of stakeholder interest.

everybody operating on the network. WELL supports working closely with contractors to improve processes, systems and operating standards through consultation, coordination and cooperation within the supply chain.

In addition, the HSW Act has caused many EDBs, including WELL, to review their live versus de-energised work policies and procedures. This has resulted in a material impact to planned outages due to the increase in de-energised planned interruptions. WELL has offset the increase in planned outages by deploying portable generators, funded through the DPP2 reliability incentive scheme. The reduction of incentives for DPP3 is likely to result in a significant reduction in portable generator usage from 2021 onwards. These effects and WELL's use of generators are further discussed in Section 6.

1.4 Service Levels

WELL continues to deliver services to customers and other stakeholders within the region at one of the highest availability levels in the country. In accordance with WELL's mission and stakeholder feedback, WELL has identified three service level measures for the period covered by the AMP. These are:

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

1.4.1 Safety Performance

WELL continues to build on its strong foundation, set by past health and safety performance. Continual improvement in managing health and safety is at the core of WELL's values and involves ongoing review of health and safety practices, systems, controls (and their effectiveness) and documentation.

WELL welcomed the change in legislation to continue to improve workplace safety and focus on effective identification and management of risks to protect the welfare of workers engaged in delivering services, as well as the safety of the public. Within this context of continuous improvement, four primary measures are used:

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

Planning Period Targets and Initiatives

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

- Maintain the number of addressed hazard observation events reported per annum at approximately 200;
- Maintain contractor engagement through site visit assessments at 400 per annum, while continually reducing resulting actions;

- Achieve a zero LTIFR over the whole period; and
- Achieve a zero TNEFR over the whole period.

During 2020 focus will be placed on the following areas to further improve performance:

- Reinforcement of WELL's safety brand "safer together";
- Increased emphasis on the wellbeing (physical and mental) of staff and field workers via focussed programmes and engagements;
- Maintain the timeliness of close-out of assessments;
- Reinforce the application of the risk management framework and expand the risk assessment process with clear focus on critical risk and control management and principal/contractor communications;
- Maintain site visits to further engage and consult workers on safety culture and supportive behaviours;
- Continue to expand the consultation, coordination and cooperation where work involves overlapping Person Conducting a Business or Undertaking (PCBU) duties; and
- Increase collaboration with field service providers in the development of practical and effective risk controls.

1.4.2 Customer Experience

It is important that WELL balances services that customers require with what value they place on these now and into the future. WELL uses insights received from customer engagement to test that the right service levels are being provided and to inform investment plans for the planning period.

In addition to good reliability and appropriate prices, customers increasingly expect accurate and timely information on their service and its status. Most customers accept occasional power cuts, but the ability to keep them informed as to when supply will be restored is also important. Ensuring good customer service means a reliable and effective information flow is a priority. To continue providing effective information to customers, WELL sets and tracks performance targets for the customer contact centre.

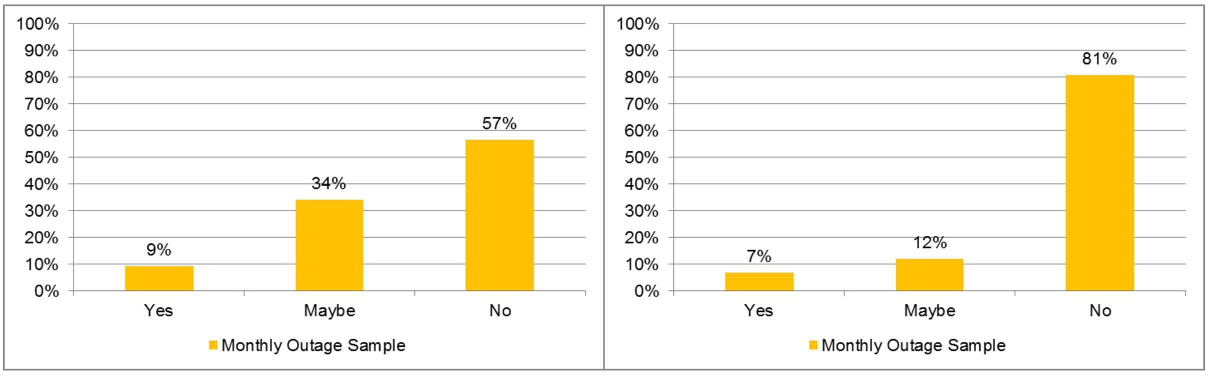
1.4.2.1 Customer Engagement

WELL engages with customers via the various initiatives it undertakes, such as electric vehicle (EV) charging trials. There has also been collaborative work undertaken in a similar technology space with a retailer trialling the use of domestic photovoltaics (PVs) and batteries within the region.

Larger customers were consulted as part of the SCPP for earthquake readiness expenditure with support being given by members of all four City Councils, the Greater Wellington Regional Council, the Wellington Lifelines Group, Major Electricity Users' Group (MEUG) and the Wellington Chamber of Commerce amongst others.

During 2019, there were two material Transpower outages that reduced the security to WELL customers supplied from Central Park and Gracefield Grid Exit Points (GXPs). WELL organised a workshop with Transpower and a cross-section of Wellington business stakeholders to understand the engagement that the community thinks is reasonable for these kinds of situations. Participants were highly engaged over the reduced security situation. They want to be informed about forecast and unplanned N-security situations and use their own discretion as to which events are of sufficient concern to prompt their own electricity outage response plans. As a result, WELL and Transpower updated the communication protocol for major GXPs which includes escalation processes and how stakeholders will be informed.

To understand the impact of outages on connected customers, WELL surveys the communities who have recently had an outage to understand whether the price-quality trade-off of the service they receive is appropriately balanced. The results for two key questions from the survey undertaken in 2019 are shown in Figure 1-1.



Q1. Would you be prepared to pay a bit more for your power if it meant fewer power cuts?	*Q3. Would you be prepared to have slightly more power cuts if it meant your electricity bill was a bit lower?*

Figure 1-1 Sample of 2019 Customer Survey Results

These results suggest that customers are broadly satisfied with their current level of reliability and the price for delivering that service.

WELL continues to operate a web-based outage application "OutageCheck" to provide information on the location and forecast restoration times for unplanned outages. The application has resulted in positive feedback from customers and a reduction in calls to the contact centre. WELL has established new services on the existing website to make the process of applying for a new connection easier to understand by:

- Providing improved background information on types of connection option and the various times, complexity and cost impacts of each option to customers;
- Integrating WCC streetlight outage reporting into the OutageCheck application; and
- Adding self-service tools to allow customers to start the order and/or enquiry process. This will help streamline the front end of this process and will guide customers through the process.

WELL has two customer related performance measures. These are:

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

1.4.2.2 Power Restoration Service Level Targets

WELL's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to Urban and Rural customers. These service levels reflect previous feedback from WELL customers and are agreed between WELL and all retailers. The targets for power restoration service levels remain consistent over the planning period 2020-2030 and are shown in Table 1-2.

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Table 1-2 Standard Power Restoration Service Level Targets 2020-2030

1.4.2.3 Contact Centre Performance

WELL has developed a set of key performance indicators (KPIs) that provide service level benchmarks for the Contact Centre (Telnet). The eight reported service level performance measures for the Contact Centre are summarised in Table 1-3.

	Service Element	Measure	Target 2020 to 2030
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
B5	Restoration Notification	Energy retailers notified and the WELL website updated within the time threshold from the time of restoration	<5 minutes

Table 1-3 Contact Centre Service Level Targets 2020-2030

1.4.3 Reliability Performance

WELL's network performance is among the best levels of electricity supply in the country. The regulatory regime that applies to WELL sets reliability caps and collars for each year from 2015/16 to 2020/21. 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 performance reward or penalty apply if the company's performance is better than or below the target respectively. The target and upper limit for WELL up to 2021 are presented in Table 1-4. Exceeding the limit would result in the Commission undertaking a formal investigation of WELL's reliability performance.

Quality Measure	Annual SAIDI	Annual SAIFI
Target	35.44	0.547
Limit	40.63	0.625

Table 1-4 WELL Annual Regulatory Reliability Targets and Limits to 2020/21

On 1 April 2021, WELL will move onto the new DPP3 Determination. DPP3 introduces significant changes to how network reliability is measured and reported. Changes include the separation of Planned and Unplanned outages into separate compliance standards, and the Unplanned compliance standard being tested annually instead of on the basis of two years out of three.

The SAIDI and SAIFI targets against the historical performance are shown in Figures 1-2 and 1-3. The 2019/20 year includes a forecast to account for March 2020 shown in dark blue.

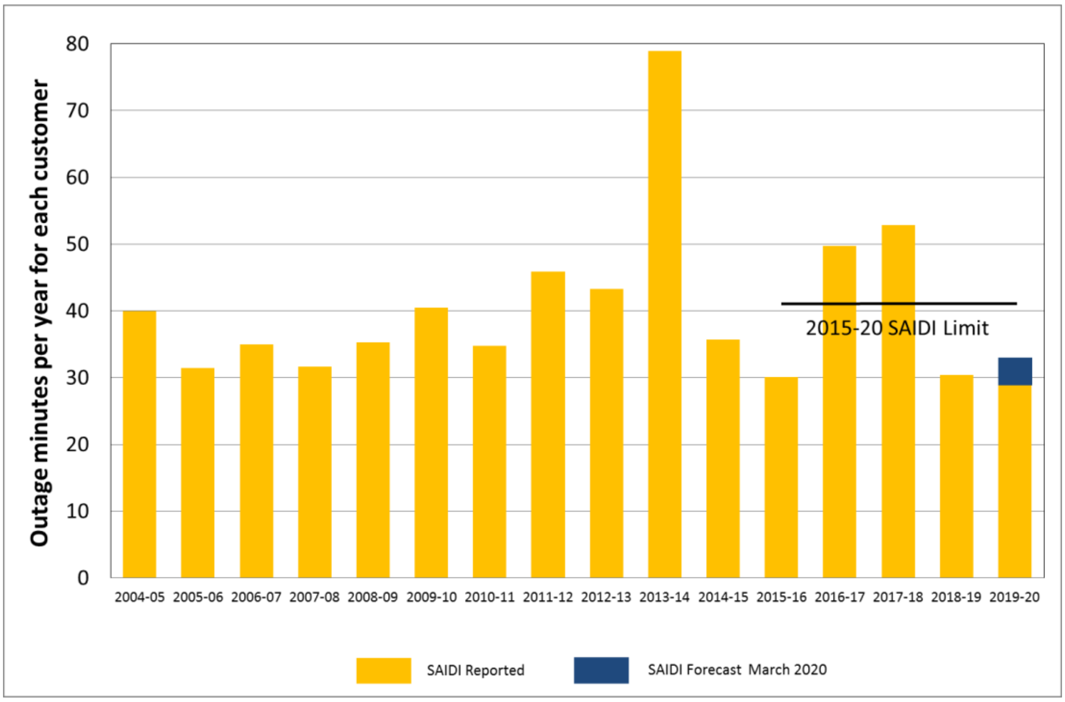


Figure 1-2 WELL SAIDI Performance

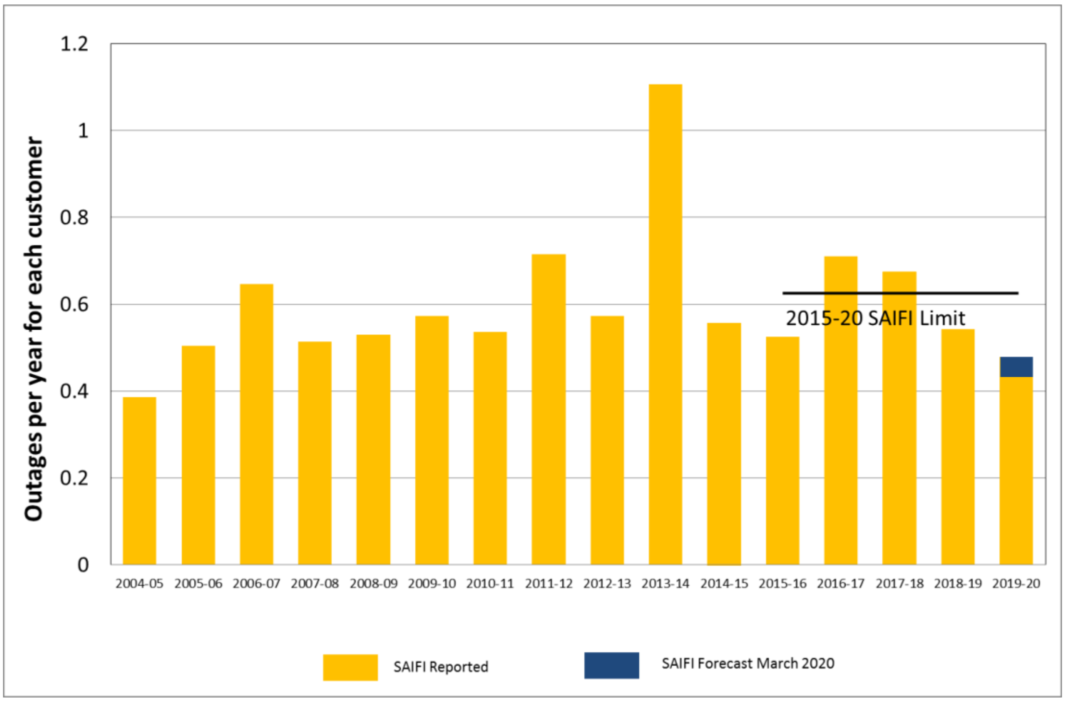


Figure 1-3 WELL SAIFI Performance

WELL has consistently demonstrated a commitment to meet reliability targets. Some of the initiatives that improved the reliability performance of the network are highlighted below:

- The feeder improvement programme to improve the quality of supply experienced by customers in areas that have a higher risk of outages;
- Analysis of incidents and outages to identify continual improvement opportunities. This has included, for example, a greater use of portable generators to reduce the impact to customers of planned outages; and
- Extended the use of asset survival curves to link forecast expenditure to asset failure rates in order to forecast and maintain reliability levels.

This good performance of the network components has compensated for higher planned outages and an increase in car vs pole events. Analysis of the main causes of the network performance and WELL's initiatives to respond in future years is provided in Sections 5 and 6.

1.5 Trend in Energy Consumption and Demand

The historic volume of energy supplied through the network declined at an average rate of ~0.7% per annum from 2012 to 2018. However, the past two years have seen a trend of increased volumes as shown in Figure 1-4.

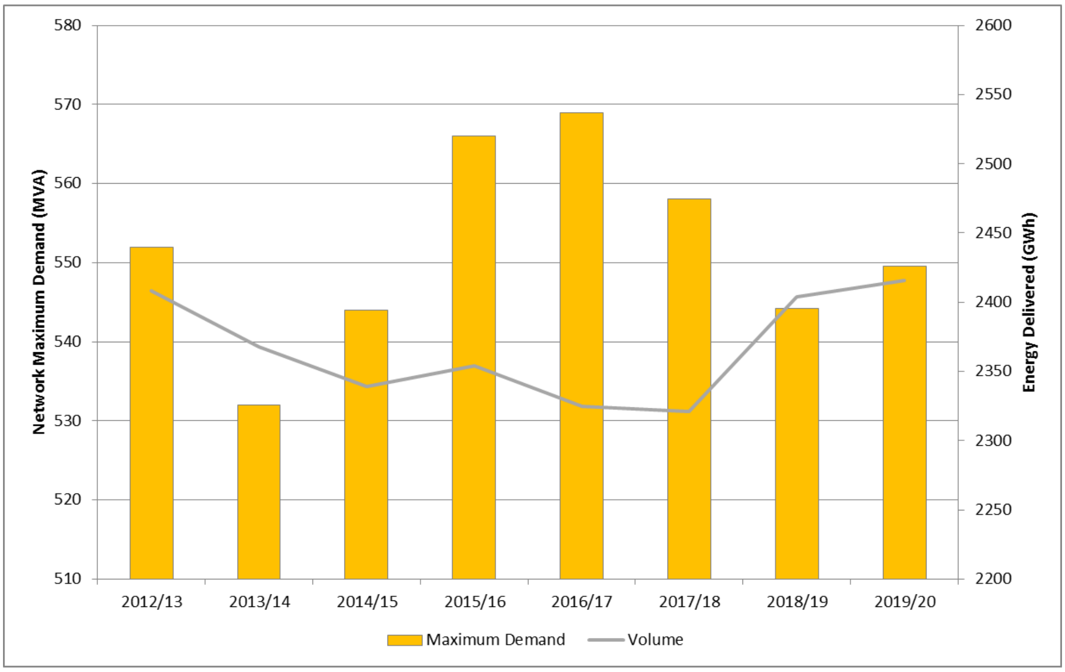


Figure 1-4 Trend in Maximum Demand and Energy Consumption

Actual consumption on the network will be driven by seasonal temperature variations and the associated customer responses, the uptake of emerging technologies, and the timing of large-scale one-off customer-led developments. WELL has a winter peaking network and a colder than usual winter or a higher uptake of EVs would drive both an increase in energy demand and consumption.

Changes in consumption patterns can also depend on clear cost reflective pricing signals to enable customers to make informed energy use decisions. Both the Electricity Authority and the Electricity Price Review highlighted the importance of clear pricing signals to manage congestion and to allow customers to make informed energy choices when they consider emerging technology.

1.5.1 Demand Forecast

The number of residential building consents issued in the Wellington region is still high, driven by the growth in apartments within the Wellington CBD and subdivision growth along the north western area of the network. Figure 1-5 shows the number of new dwellings consented over the last six years. WELL expects this growth to stabilise over time.

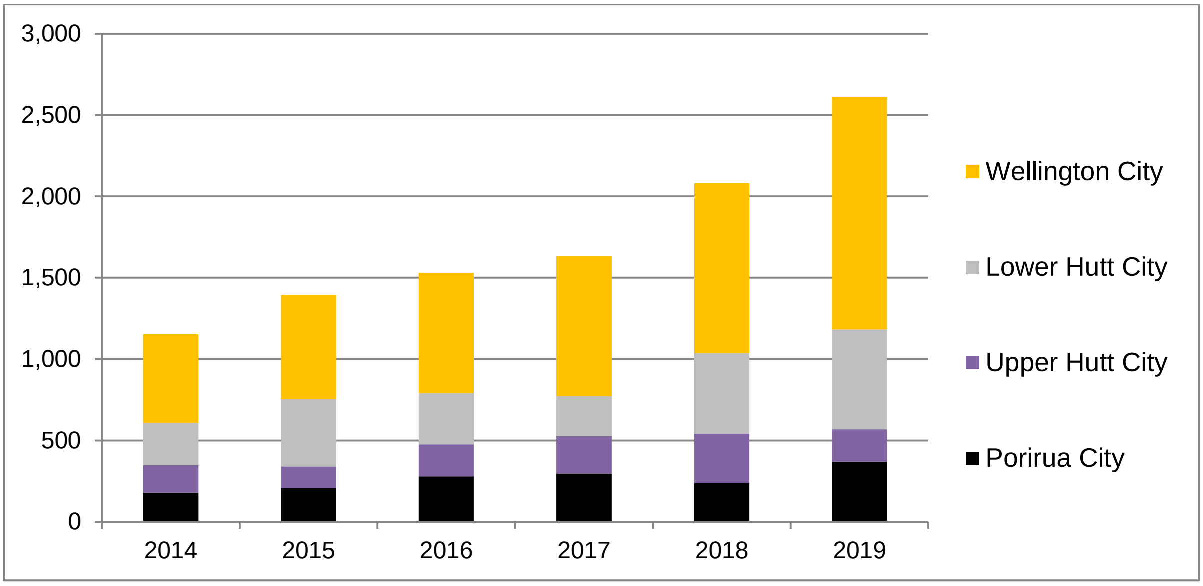


Figure 1-5 Number of New Dwellings Consented in the Wellington Region

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.

The sustained peak demand is forecast to grow in some localised areas of the network, driven by new commercial and residential developments. Generally, demand peaks within the Wellington region are driven by winter temperatures on the coldest days.

While the overall load in Wellington is traditionally winter peaking, recent trends have shown that a few of the zone substations within the Wellington city are now summer peaking.

Figure 1-6 illustrates the forecast peak demand (system maximum demand) for the last five years and the forecast for the next 10 years.

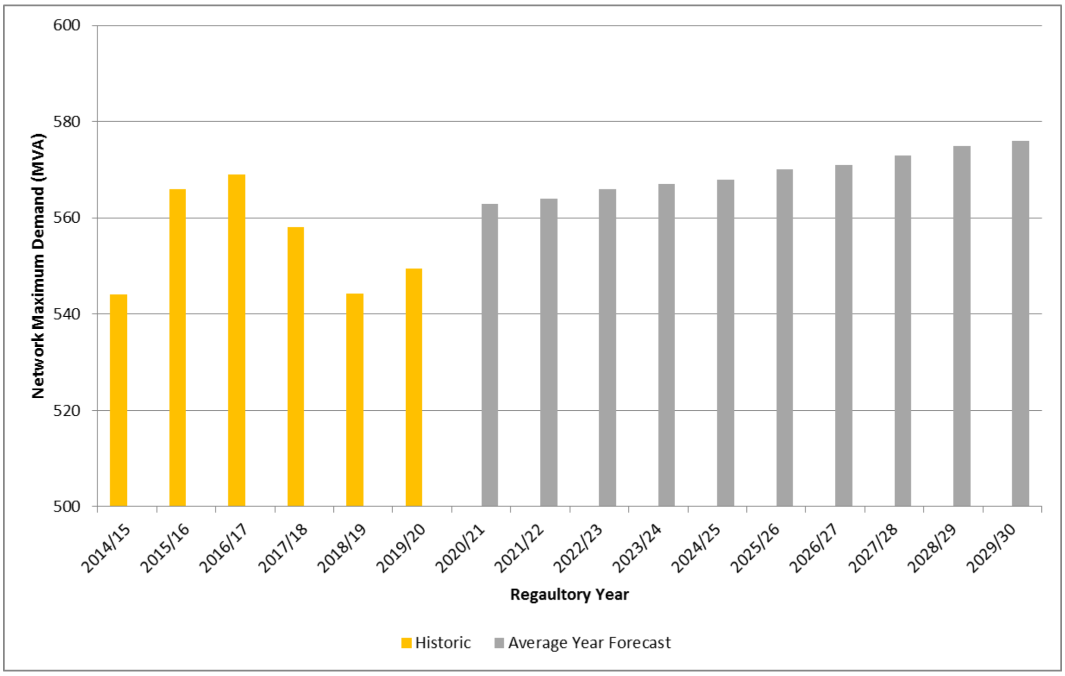


Figure 1-6 Network Historic and Forecast Maximum Demand

The evolution of technology supported by different pricing plans and business models will incentivise customer behaviour and technology choices which will help support decisions for efficient network investment. Therefore the investment profile in future years will continue to change as forecasts are updated.

1.6 Network Expenditure

Network growth forecast expenditure has increased from the 2019 AMP forecast to create the required capacity headroom for future growth.

1.6.1 Network Capital Expenditure

WELL separates the network capital expenditure forecast into five categories:

1. Asset Renewal - includes specific replacement projects identified in the fleet summaries and routine replacements that arise from condition assessment programmes. This is driven by the replacement of assets such as poles, switchgear and 11 kV/400 V substations.

2. Reliability, Safety and Environment - includes expenditure that is not directly the result of asset health drivers, including supply projects targeting the worst performing feeders and the seismic building reinforcement programme as well as other SCPP readiness works.

3. System Growth - driven by system development needs and is dependent on the timing and location of peak demand growth and other areas of growth on the network.[4]

4. Relocation Capital – expenditure required to relocate assets primarily due to roading projects and where the cost is normally shared with NZTA.

5. Customer Connection – includes the costs to deliver customer requested capital projects, such as new subdivisions, customer substations or connections.

The network capital expenditure, both historical and forecast, is shown in Figure 1-7.

[4] There has been an addition of extra funding associated with new technologies that has been incorporated into the System Growth category. This is currently not funded and has been added on as an addition over and above existing allowances.

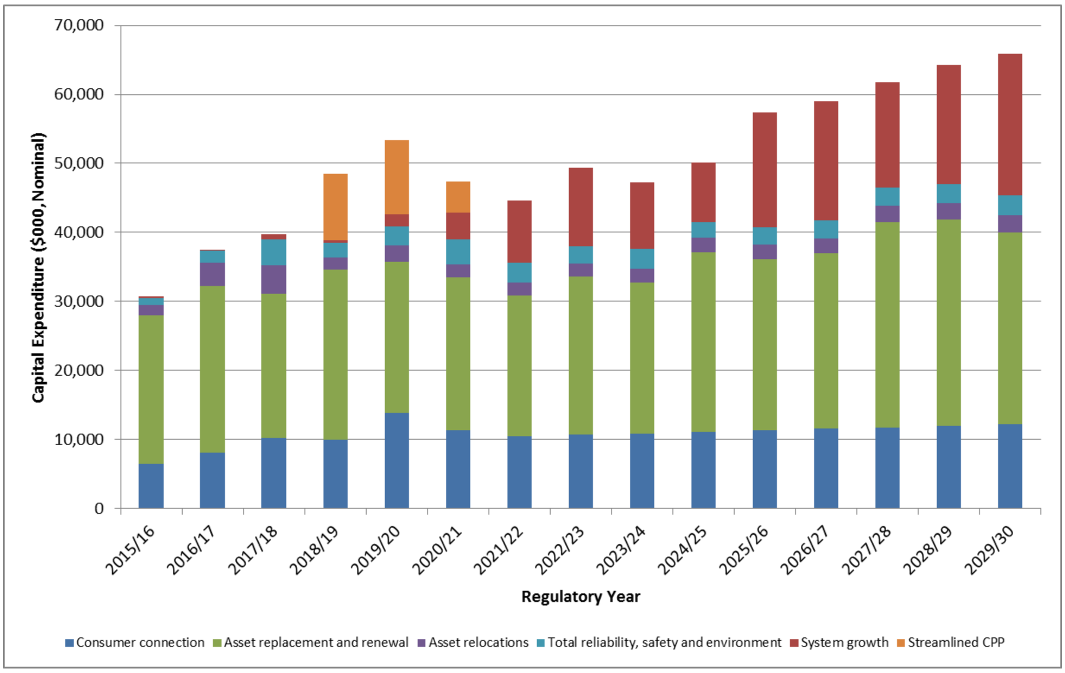


Figure 1-7 Network Capital Expenditure
($K in nominal prices)

The variability of the forecast capital expenditure is driven mainly by the SCPP, System Growth projects required to accommodate localised peak demand growth, and variability in the larger 33 kV cable and power transformer replacement projects in the Asset Renewal category.

1.6.2 Network Operational Expenditure

WELL separates network operational expenditure forecast into four categories:

1. Service interruptions and emergencies – includes work that is undertaken in response to faults or third party incidents, and includes equipment repairs following failure or damage.
2. Vegetation management – covers planned and reactive vegetation work, through a risk-based programme in addition to cut/trim zone administration.
3. 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.
4. Asset replacement and renewal - includes repairs and replacements that do not meet the requirements for capitalisation.

The network operational expenditure, both historical and forecast, is shown in Figure 1-8.

Figure 1-8 Network Operational Expenditure
($K in nominal prices)

1.7 Capability to Deliver

WELL 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 WELL is part of the CK Infrastructure Holdings Limited group it has access to relevant skills and experience from across the world. This provides WELL with direct access to international best practice systems and visibility of new technology trials.

WELL's Board of Directors and senior management team have reviewed this AMP against the business strategy to ensure alignment with business capability and priorities as well forecasted new technology developments.

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 April 2018). It describes WELL's long-term investment plans for the planning period from 1 April 2020 to 31 March 2030.

On 26 March 2020, the Commission granted a one month extension to the deadline for Asset Management Plans, in response to the COVID-19 pandemic. The document was approved for disclosure by the WELL Board of Directors on 9 April 2020.

2.1 Purpose of the AMP

The purpose of this AMP is to:

- Be the primary document for communicating WELL's asset management practices and planning processes to stakeholders;
- 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, WELL'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".*

WELL's asset management practices summarised in this AMP inform WELL'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 WELL's business and the operational environment. The body of the AMP is structured into the following three categories:

- **Overview and Approach** which provides an overview of WELL and the approach taken to asset management;
- **Performance Targets and Levels of Service** which provides an overview of the various safety, customer and reliability targets that WELL is measured against and WELL's performance against those targets; and
- **10 Year Investment Plan** which describes WELL'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.

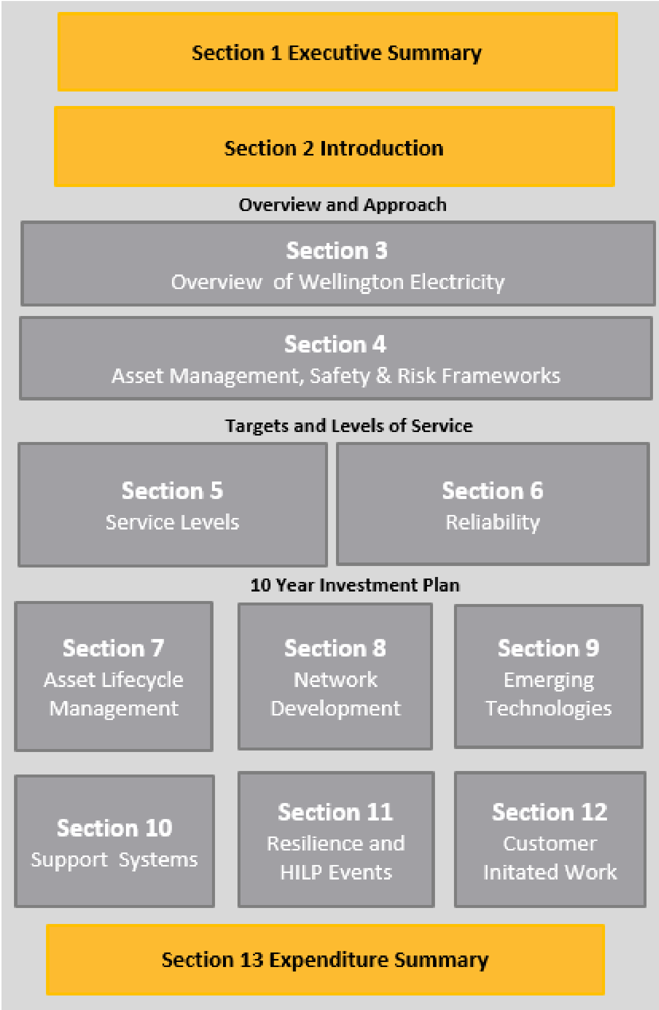


Figure 2-1 Structure of the 2020 AMP

2.3 Formats used in this AMP

The following formats are adopted in this AMP:

- Financial values are in constant price 2020 New Zealand dollars, except where otherwise stated;
- Calendar years are referenced as the year e.g. 2020. WELL'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. 2020/21;
- All asset data expressed in figures, tables, and graphs is at 31 October 2019 unless otherwise stated;
- ICP numbers are as at December 2019; and
- All asset quantities or lengths are quoted at the operating voltage rather than at the design voltage. For example, WELL has 17km of 33 kV cable operating at 11 kV. The length of these cables is incorporated into the statistics for the 11 kV cable lengths and not the 33 kV cables.

2.4 Investment Projections

The investments described in this AMP underpin WELL's 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 is driven by:

- The need to provide a safe environment that is free from harm for staff, contractors and the public;
- The need to understand customers ongoing requirements to maintain a reliable supply;
- The current understanding of the condition of the network assets and risk management;
- Assessment of load growth and network constraints;
- New and emerging technologies and their role in the future operations of WELL as a Distribution Network/System Operator to meet changing consumer needs;
- Changes to business strategy driven by internal and external factors; and
- The impact of the regulatory regime.

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

The investment projections outlined in this AMP include both business as usual costs and the expenditure approved under the Streamlined Customised Price Path (SCPP) to improve WELL's earthquake readiness. These additional earthquake readiness projections have been included into the resilience works in Section 11 and the Schedules in Appendix C.

Further indicative forecasts have also been included into Section 11 for future works to further enhance the long term resilience of key network assets in preparation for a major catastrophe. These future works have not been included into the overall capex projections in Appendix C. This is due to the current regulatory mechanism being unable to feasibly support such expenditure.

The forecasts related to new technology trials have been included in Section 9 and have been included as part of the capex forecasts in the system growth category of Appendix C.

There may still be a need for increased reinforcement as the signalled shift away from fossil fuels will see consumers turn to the use of electricity. This investment has not been factored into this plan as forecasts for reduced gas availability, and the large scale transition of vehicle manufacturing from fossil fuels to electricity, are beyond the 10 year planning horizon.

As described above, WELL'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.

Section 3

Overview of WELL

3 Overview of WELL

This section provides an overview of the WELL business, its mission and how this translates to the asset management framework. It also describes WELL's corporate structure, governance, asset management accountabilities, the area supplied, description of the network, the 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 Strategic Alignment of this Plan

WELL'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. To achieve its mission WELL's business and asset management practices and policies must:

- Provide a safe environment that is free from harm 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 both the current and future regulatory environments.

The mission and these core principles are reflected in WELL'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 supported by WELL's asset management framework, objectives and strategies, which are used to inform its 2020 Business Plan. It takes into account the interests of consumers, stakeholders, and the changing operating environment (as discussed further in Section 3.6). Figure 3-1 illustrates this flow from WELL's mission to the Business Plan to the AMP.

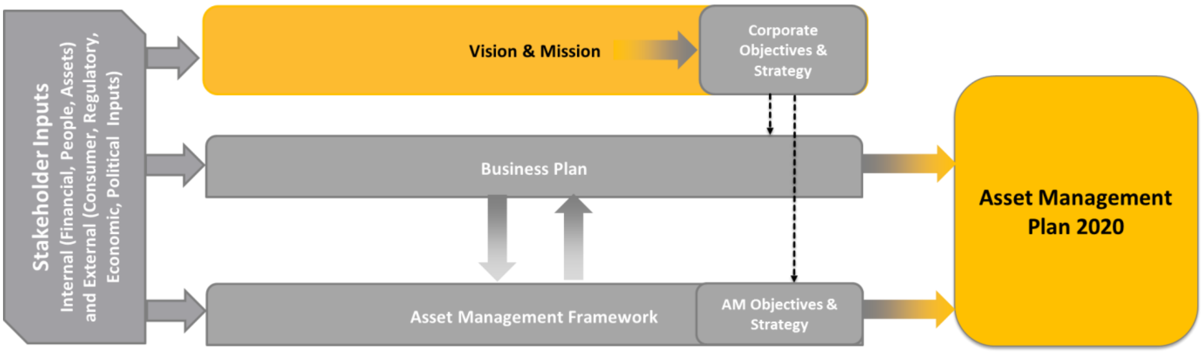


Figure 3-1 Interrelationship between WELL's Mission, the Business Plan, the Asset Management Framework and the AMP

The Asset Management Framework utilised by WELL is discussed further in Section 4.

3.2 Organisational Structure

3.2.1 Ownership

Cheung Kong Infrastructure (BVI) Ltd. and Power Assets Holdings Limited together own 100 per cent of WELL. Both shareholding companies are members of the CK Infrastructure Holdings Limited group of companies, which are listed on the Hong Kong Stock Exchange.

The CK Infrastructure Holdings Limited group has established a strong global presence with investments in electricity sectors of countries throughout the world. Having the support and backing of such an organisation puts WELL in a strong position to leverage a large amount of intellectual property, resources, and to access the latest developments in the electrical services industry.

WELL is part of a colloquium of electrical sector companies (such as Hong Kong Electric, CitiPower/ Powercor, United Energy, SA Power Networks and UK Power Networks[5]) which meets via conference to discuss the latest developments in new technologies from around the globe.

In addition, WELL attends joint Cheung Kong Infrastructure (BVI) Ltd. and Power Assets Holding Ltd. technical conferences and safety conferences where the latest trends and initiatives from all business partners across the group are shared.

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

3.2.2 Corporate Governance

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

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

3.2.3 Executive and Company Organisation Structure

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

IISC is a separate infrastructure services company, part of CK Infrastructure Holdings Limited which provides business support services to WELL. IISC provides the in-house financial, regulatory, asset management and planning functions as well as 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 WELL's activities.

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

[5] Further details of electrical sector sister companies that are part of CK Infrastructure Holdings Limited can be found on the website - www.cki.com.hk

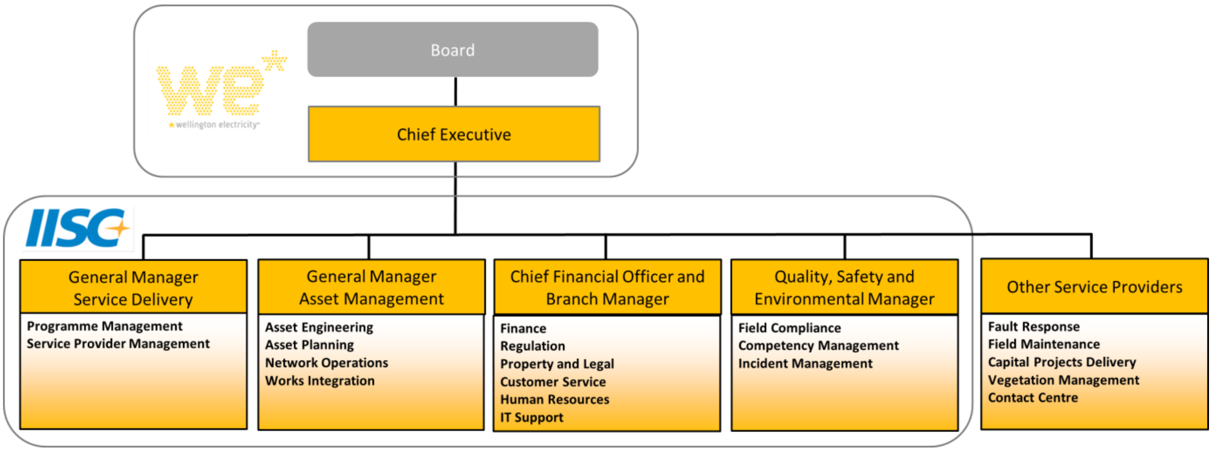


Figure 3-2 WELL Organisation Structure

3.2.4 Financial Oversight, Capital Expenditure Evaluation and Review

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

3.2.4.1 Major Project Financial Approval and Governance

The policies for Authorisation and Payment of Project Expenditure together with the individual DFAs, define the procedure for authorisation of WELL's capital expenditure[6].

Capital projects above $400,000 are reviewed and approved by the Capital Investment Committee (CIC), a subcommittee of the Board, who review the project business case and approves the expenditure.

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

3.2.5 Asset Management Accountability

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

The General Manager – Asset Management is accountable for asset engineering, network planning, standards, project approvals, works prioritisation, works integration and the network control room. Responsibilities also include the management and introduction of new technology onto the network.

The General Manager – Service Delivery is accountable for delivery and 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 is accountable for all indirect business support functions including finance, customer service, regulatory management, legal and property management, human resources and information technology support.

[6] Approval of operational expenditure follows a similar process.

WELL'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's responsibilities are separated into four areas: asset engineering, network planning, network control & operations and works integration. The responsibilities for each area are described in Table 3-1.

Asset Management Teams	Asset Management Responsibilities
Asset Engineering	• Safety-by-Design for asset replacements • Asset and network management • Condition based risk management • Reliable service levels for customers • Approval of asset management projects, plans, and budgets • Quality performance management • Network policies and standards • Technical engineering support
Asset Planning	• Safety-by-Design for new builds • Network load forecasting • Strategic network development and reinforcement planning • Large customer connection requests • Secondary system management • Introduction of new technology onto the network • Engineering support
Network Operations	• Network operations and safety • Outage management • Fault response and management • Control Room • Operationalising new technologies onto the network
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 • WELL's thought leadership on core asset management applications

Table 3-1 Asset Management Team Responsibilities

3.2.5.2 Service Delivery Team

The Service Delivery team responsibilities are separated into four 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 Table 3-2.

Service Delivery Team	Asset Management Responsibilities
Network Portfolio	• Delivery of contestable network-initiated projects
Customer Portfolio	• Delivery of contestable customer-initiated projects
Totex	• Delivery of the corrective and preventative maintenance programmes, and exclusive capital works projects, under the Field Services Agreement (FSA)
Contract Management	• Delivery of reactive maintenance and value add services under the FSA • Management of specialist contracts, for example vegetation management, the Chorus agreement, and the Mill Creek maintenance contract.

Table 3-2 Service Delivery Team Responsibilities

3.2.5.3 Commercial and Finance Team

The Commercial and Finance team responsibilities are described in Table 3-3.

Commercial and Finance Team	Asset Management Responsibilities
Commercial & Regulatory	• Compliance to regulatory requirements
Finance	• Adequate funding of asset management plans
Customer Manager	• Accountable for customer relations management including cost quality surveys.
Legal and Property Manager	• Corporate risk management • Management of property and land
HR Manager	• Capability of people to deliver Asset Management functions

Table 3-3 Commercial and Finance Team Responsibilities

3.2.5.4 QSE Team

The QSE team responsibilities are described in Table 3-4.

QSE Team	Asset Management Responsibilities
QSE	• Quality processes and procedures in place to manage delivery of asset management plans • Adherence to Health & Safety and Environmental legislation

Table 3-4 QSE Team Responsibilities

WELL outsources the majority of its field services tasks and its customer contact centre. WELL maintains the overarching accountability for health and safety of all contracted parties. Management of the field service provider contracts is the responsibility of the General Manager – Service Delivery. Management of the customer contact centre contract falls within the Chief Financial Officer’s responsibilities.

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

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

The contracts with outsourced service providers are structured to align with WELL's asset management objectives and to support continuous improvement in the integrity of the asset data held in WELL's information systems.

The roles and service provided by the service providers are explained in further detail in Section 4 (Asset Management Delivery).

3.3 Distribution Area

WELL is an Electricity Distribution Business (EDB) that provides infrastructure to support the distribution of electricity to approximately 169,500 consumers in its network area, represented by the yellow-shaded area in Figure 3-3. 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 has few large industrial and agricultural loads.

Each local authority in the area (Wellington, Porirua, Hutt and Upper Hutt City Councils) has different requirements relating to permitted activities for an electrical distribution business. 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 Greater Wellington Regional Council.

Prior to deregulation, network development in the region was the responsibility of two separate organisations and consequently the equipment utilised and the network design standards differed between the two historic network areas. One historic area now supplies the Southern region of WELL's network. The other historic area has been further split into the Northwest and Northeast areas to reflect the natural geographical and electrical split between the areas. These three areas are shown in Figure 3-3.

The three areas which are used for planning purposes are: 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 3-3 WELL Network Area

3.4 The Network

The total system length of WELL's network (excluding streetlight circuits) is 4,756 km, 64% 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 33 kV and 11 kV, and Kaiwharawhara supplies at 11 kV only. The remaining GXPs (Gracefield, Pauatahanui, Takapu Rd, Upper Hutt and Wilton) all supply the network at 33 kV only.

The 33 kV subtransmission system distributes the supply from the Transpower GXPs to 27 zone substations at N-1[7] security level. The 33 kV system is radial with each circuit supplying its own dedicated

[7] N-1 = Available capacity in the event of a single component failure. The majority of sites have redundant capacity by design in the form of a second backup component, i.e. two independent subtransmission circuits supply each zone substation with sufficient capacity for the total load at the zone substation.

power transformer, with the exception of Tawa and Kenepuru where two circuits from Takapu Road are teed to supply four transformers (two at each substation). All 33 kV circuits supplying zone substations in the Southern area are underground while those in the Northwestern and Northeastern areas are a combination of overhead and underground. The total length of the 33 kV system is 195 km, of which 138 km is underground. A single line diagram of the subtransmission network is included in Appendix F.[8]

The 27 zone substations incorporate 52 33/11 kV 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 33 kV supply to a single power transformer. However, the substations are connected by an 11 kV tie cable and as a result they operate as a single N-1 substation with a geographic separation of 1.5 km.

The zone substations in turn supply the 11 kV distribution system which distributes electricity directly to the larger consumers and to 4,373 distribution transformers located in commercial buildings, industrial sites, kiosks, berm-side and on overhead poles. The total length of the 11 kV system is approximately 1,771 km, of which 67% is underground. 71% of the 11 kV feeders in the Wellington CBD[9] 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 2,790 km, of which 61% is underground. An additional 1,923 km of LV lines and cables are dedicated to providing street lighting services.

WELL's three network areas are described in further detail below.

3.4.1 Southern Area

The Southern Area network is supplied from the Central Park, Wilton, and Kaiwharawhara GXPs, which together supply Wellington City, the Eastern Suburbs and the CBD. Figure 3-4 illustrates the Southern Area subtransmission network configuration.

[8] Further information on the demarcation points between WELL and its stakeholders can be found in the WELL Distribution Code and on the WELL website.

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

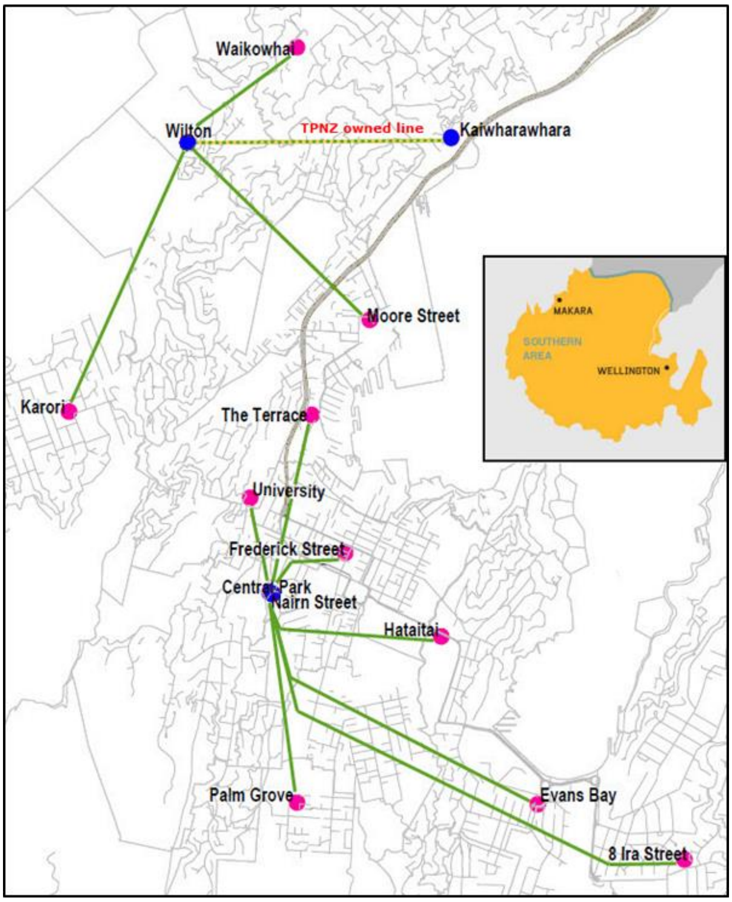


Figure 3-4 Wellington Southern Area Subtransmission Network

3.4.1.1 Central Park

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

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

Central Park GXP supplies seven WELL zone substations at Ira Street, Evans Bay, Hataitai, Palm Grove, Frederick Street, University, and The Terrace each via double circuit 33 kV underground cables. Central Park GXP also supplies the WELL Nairn Street switching station adjacent to Central Park at 11 kV via two underground duplex 11 kV circuits (four cables). The security of supply from Central Park has been identified as a risk and solutions are discussed in Section 11.

3.4.1.2 Wilton

Transpower's Wilton GXP comprises two 220/33 kV transformers (100 MVA units) operating in parallel, supplying their 33 kV indoor bus. Wilton supplies three WELL zone substations at Karori, Moore Street, and Waikowhai Street each via double circuit underground cables.

3.4.1.3 Kaiwharawhara

Kaiwharawhara is supplied by two 110 kV circuits from Wilton GXP, and has two 38 MVA 110/11 kV transformers in service. WELL takes 11 kV supply from Transpower's Kaiwharawhara GXP and distributes this via a WELL owned switchboard (with 14 feeders) 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.

3.4.1.4 Southern Area Summary

Supply Point	Connection Voltage (kV)	Sustained Maximum Demand – 2019 (MVA)	Firm Capacity[10] (MVA)	Volumes – 2019 (GWH)	ICP Count[11]
Central Park 33 kV	33	133	228	669	42,217
Central Park 11 kV	11	21	30	104	6,852
Wilton 33 kV	33	36	106	209[12]	12,445
Kaiwharawhara 11 kV	11	28	41	149	5,814
Total				**1,131**	**67,328**

Table 3-5 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 3-5 illustrates the Northwestern Area GXP and subtransmission network configuration.

[10] Firm Capacity is the N-1 transformer capacity.
[11] This includes active and disconnected ICP's
[12] This includes 206 GWh injected by Mill Creek Generation

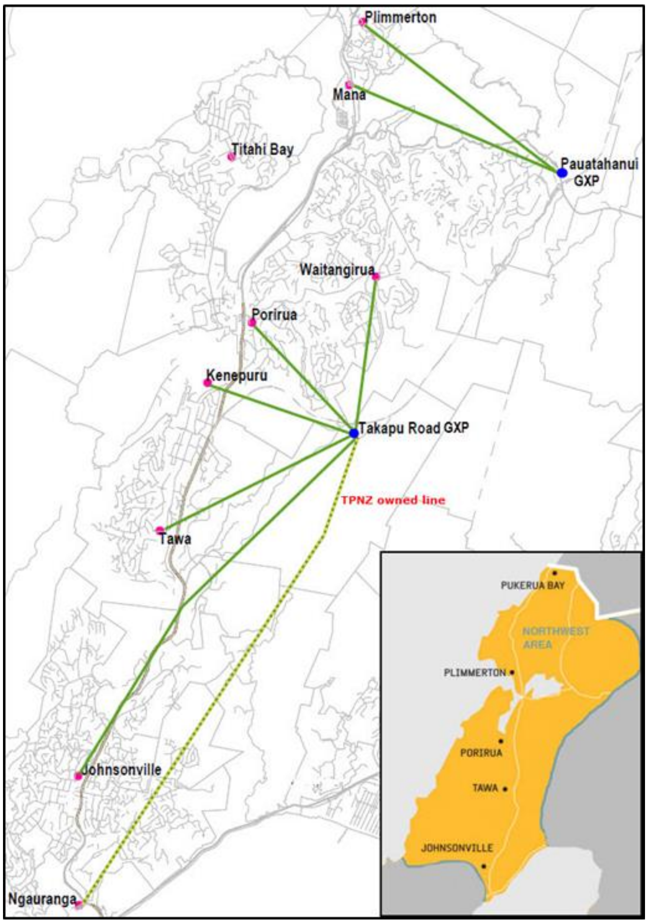


Figure 3-5 Wellington Northwestern Area Subtransmission Network

3.4.2.1 Pauatahanui

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

3.4.2.2 Takapu Road

Transpower's Takapu Road GXP comprises two parallel 110/33 kV transformers nominally rated at 90 MVA each supplying their 33 kV indoor bus. Takapu Road GXP supplies six WELL zone substations at Waitangirua, Porirua, Tawa, Kenepuru, Ngauranga and Johnsonville, each via double 33 kV circuits. These circuits leave the GXP as overhead lines across rural land and become underground cables at the urban boundary. Transpower has recently informed WELL that they intend to decommission the circuit from Takapu Road to Ngauranga Zone Substation, which is a 110 kV circuit being operated at 33 kV. The forecasts in this AMP have assumed that this circuit is still maintained and in operation.

3.4.2.3 Northwestern Summary

Supply Point	Connection Voltage (kV)	Sustained Maximum Demand – 2019(MVA)	Firm Capacity (MVA)	Volumes – 2019 (GWH)	ICP Count[13]
Pauatahanui 33 kV	33	17	24	71	6,783
Takapu Rd 33 kV	33	89	123	400	33,247
Total				**470**	**40,030**

Table 3-6 Summary of Northwestern Area GXPs

3.4.3 Northeastern Area

The Northeastern Area network is supplied from the Upper Hutt, Haywards, Melling and Gracefield GXPs, which supply the Hutt Valley and the surrounding hills. Figure 3-6 illustrates the Northeastern Area subtransmission network configuration.

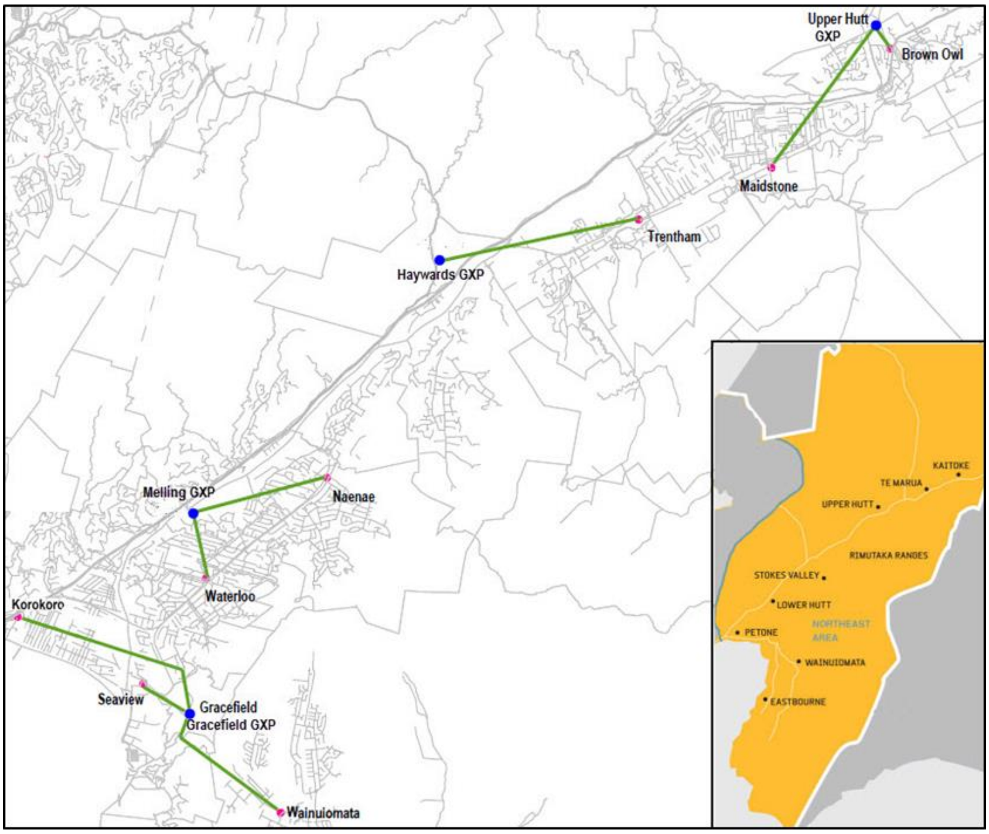


Figure 3-6 Wellington Northeastern Area Subtransmission Network

3.4.3.1 Upper Hutt

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

[13] This includes active & disconnected ICP's

3.4.3.2 Haywards

Transpower's upgraded the Haywards GXP in 2019 and this now has two parallel 110/33/11 kV transformers nominally rated at 60/30/30 MVA. WELL takes supply to two 33 kV circuits that supply Trentham zone substation, and eight 11 kV feeders.

3.4.3.3 Melling

Transpower's Melling GXP comprises two parallel 110/33 kV transformers each nominally rated at 50 MVA supplying their 33 kV indoor bus. Melling supplies zone substations at Waterloo and Naenae via duplicated 33 kV underground circuits. Melling also includes a Transpower 11 kV switchboard fed by two parallel 110/11 kV transformers each nominally rated at 25 MVA, from which WELL takes supply to ten 11 kV feeders.

3.4.3.4 Gracefield

Transpower's Gracefield GXP comprises two parallel 110/33 kV transformers nominally rated at 85 MVA each supplying their 33 kV indoor bus. In late 2019, one of the two transformers had a winding fault and Transpower has temporarily installed a 60 MVA strategic spare. Transpower is analysing the winding fault which will lead to an agreed permanent solution at the site. Gracefield GXP supplies four WELL zone substations at Seaview, Korokoro, Gracefield and Wainuiomata each via double 33 kV circuits. The line to Wainuiomata is predominantly overhead while underground cables supply the other substations. WELL's Gracefield zone substation is located on a separate site adjacent to the GXP with short 33 kV cable sections connecting the GXP to the zone substation.

3.4.3.5 Northeastern Summary

Supply Point	Connection Voltage (kV)	Sustained Maximum Demand – 2019 (MVA)	Firm Capacity (MVA)	Volumes – 2019 (GWH)	ICP Count[14]
Gracefield 33 kV	33	53	89	278	18,955
Haywards 33 kV	33	15	30	76	5,275
Melling 33 kV	33	30	52	135	11,961
Upper Hutt 33 kV	33	28	37	129	11,202
Haywards 11 kV	11	16	30	69	6,755
Melling 11 kV	11	23	27	119	7,913
Total				**805**	**62,061**

Table 3-7 Summary of Northeastern Area GXPs

[14] This includes active and disconnected ICPs

3.4.4 Embedded Generation

There is a wide range of embedded generation connected to the network, including 1,443 installations of PV with 5,017 kVA capacity. The largest embedded generation site is the 60 MW windfarm at Mill Creek which connects into WELL owned 33 kV circuits from Wilton. There are nine diesel generation sites with an installed capacity of 16.3 MVA, the largest being a 10 MVA installation at Wellington Hospital. The diesel generation serves as a mains fail backup and is not designed for backfeed operation. 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 WELL's network is given in Section 9.

3.4.5 Embedded Distribution Networks

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

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

3.5 Regional Demand and Consumer Mix

In 2019/20 WELL's network is forecast to deliver 2,416 GWh to consumers around the region. The network maximum demand during winter 2019 was 550 MW. As illustrated in Figure 3-7, the historic volume of energy supplied through the network has declined at an average rate of ~0.7% per annum from 2011 to 2018. This was due to improved energy efficiency reducing consumption (e.g. residential insulation and widespread use of LED lightings).

The past two years have seen a trend of increased volumes which is due to the stabilisation of energy efficiency benefits, an increase in new connections, and DERs like electric vehicles (EVs) connecting to the network.

On the Wellington network, the period of maximum demand is usually in the winter when household heating is higher. The maximum demand trend is therefore highly dependent on mid-winter temperature – the colder the winter, the higher the demand on the network. Maximum demand for the 2019/20 year was less than previous years due to the mild winter, and is not considered a long term trend.

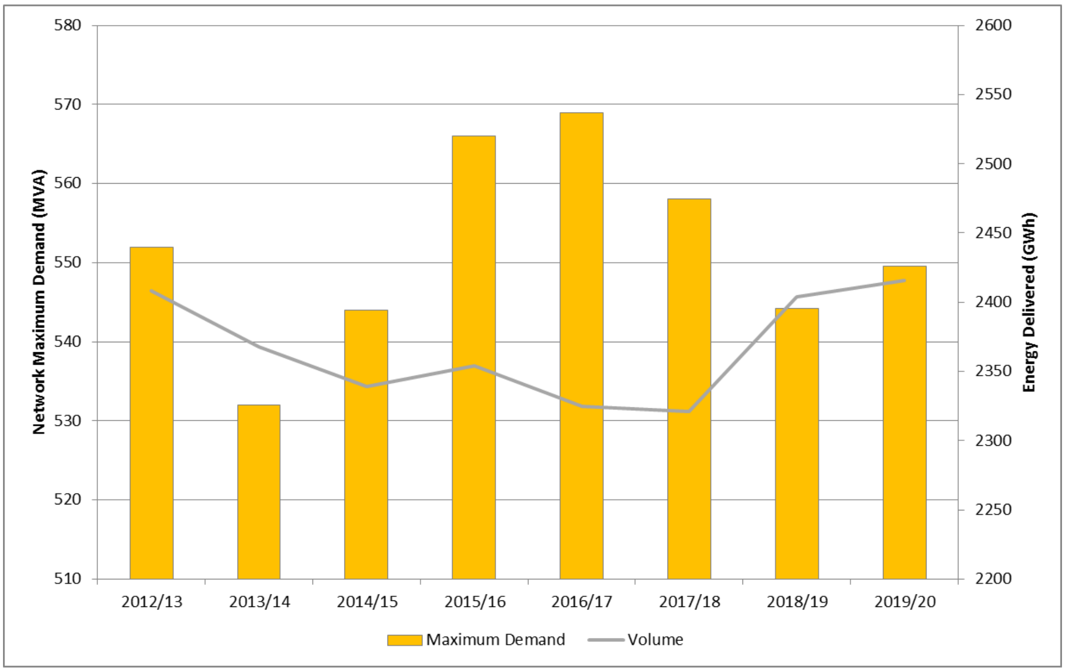


Figure 3-7 Maximum Demand and Energy Injected

As shown in Table 3-8, the overall consumer mix on the Wellington network consists of approximately 90% residential connections.

Consumer Type	ICP Count[15]
Residential	151,579
Large Commercial	453
Medium Commercial	630
Small Commercial	15,303
Large Industrial	51
Small Industrial	255
Unmetered	1148
Total	**169,419**

Table 3-8 WELL's Consumer Mix as at February 2020

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;

[15] This is only active ICP's

- 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.

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

WELL's Customer Services team is responsible for managing the needs of retailers and consumers. Major consumers have specific needs which are met on a case by case basis. This includes managing the impact of network outages and asset management priorities. 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 WELL's Stakeholders

WELL has identified nine key stakeholder groups whose interests are considered in the approach taken to asset management and required outcomes for the different stakeholder groups. These stakeholder groups are:

- Consumers and the community at large;
- Retailers;
- Regulators;
- Transpower;
- Central and local government;
- Industry organisations;
- Staff and contractors;
- Debt Capital Market Funders; 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 WELL's asset management processes. The resulting service levels sought by stakeholders, once their interests have been accounted for, are described in Section 5.

3.6.1 Stakeholder Groups

3.6.1.1 Consumers and the community at large

Consumers’ interests are identified through direct feedback (surveys) 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.

WELL also engages with communities in the new technology space such as recent EV trial projects. One trial used half-hourly metering data to measure the size and timing of electricity demand of both a group of EV-owning households (useful data was obtained for 77 of these in total), and a control group of non-EV owning households (860 in total). The objective of the EV Charging Trial was to better understand the scale of this new technology, how responsive demand is to price signals and to form a base for future time-of-use cost reflective tariffs.

WELL continues to operate a web-based outage application to provide information on the location and forecast restoration times for unplanned outages. The application has resulted in positive feedback from customers and a reduction in calls to the Contact Centre. Additional work is continuing to improve the customer experience by improving the accuracy of published estimated times of restoration.

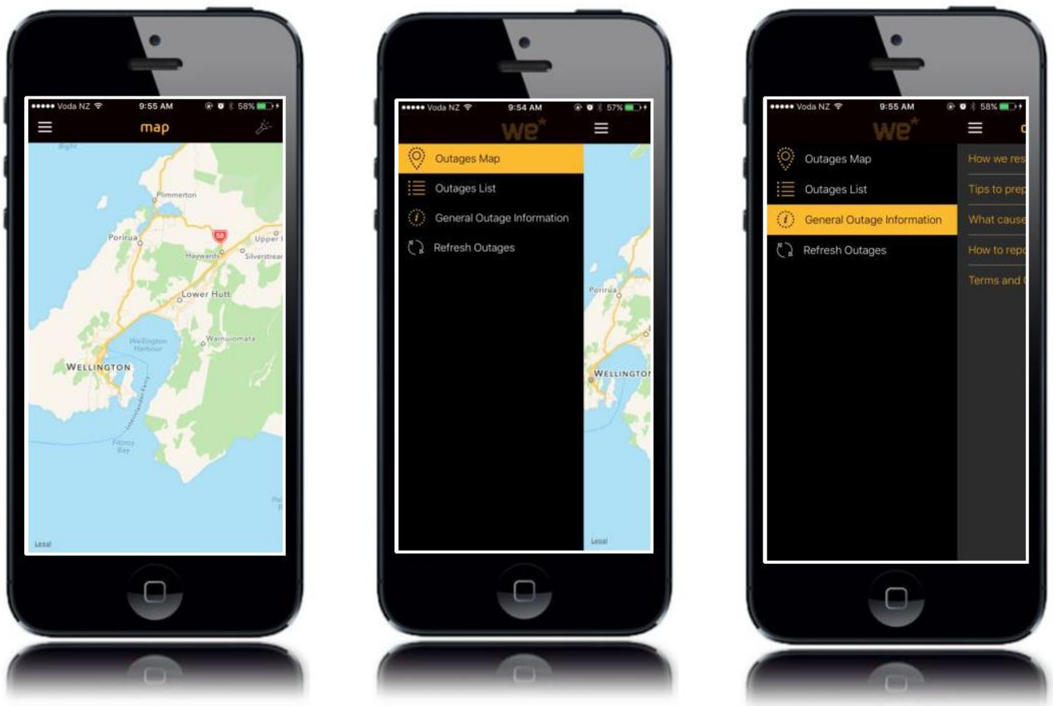


Figure 3-8 WELL's Web-based Application

WELL has established new services on the existing website to make the process of applying for a new connection easier to understand by:

- Providing improved background information on types of connection option and the various times, complexity and cost impacts of each option to customers; and

- Adding self-service tools to allow customers to start the order and/or enquiry process. This will help streamline the front end of this process and will guide customers through the process.

The updated website information and first phase of self-service tools was delivered in 2019. A second project to establish service level expectations for quote requests, dependent on the complexity of work types will be added to the website in 2020.

WELL has also engaged with targeted communities to better understand their experiences and opinions to help develop and improve the level of service and ultimately their customer experience. Examples include WELL-initiated discussions with community associations in the Whitemans Valley, Blue Mountains, Pauatahanui and Horokiwi areas.

3.6.1.2 Retailers

Retailers are WELL's direct customers. They rely on the network to deliver energy which they sell to consumers. Retailers ask that WELL assists in providing innovative products and services to benefit their consumers.

Customer supply quality interests are accounted for through meeting the quality targets and by achieving the customer service levels contained in WELL's Use of Network Agreement with retailers. WELL is working with the Electricity Authority and other market participants on an industry default Use of System Agreement (UoSA). WELL will work with retailers to decide whether to move to the new agreement or to remain on the current agreements.

WELL consults with retailers prior to the implementation of changes to its line charge pricing structure to ensure that any proposed changes take note of retailer feedback. WELL has worked with a large retailer trialling the use of PV and batteries within the region.

3.6.1.3 Regulators

The main regulators for WELL are WorkSafe New Zealand, the Commerce Commission (the Commission) and the Electricity Authority (the Authority).

Work Safe New Zealand is interested in the continuing improvement in workplace safety and effective identification and management of risk to protect the welfare of workers. These interests are accounted for in the asset management practices through a comprehensive set of health and safety, environmental, and quality policies and procedures. These include reporting requirements as well as the need to consult, cooperate and coordinate with Person's Conducting a Business or Undertaking (PCBUs). WELL has an audited Public Safety Management System (PSMS) that covers the management of assets installed in public areas to ensure that they do not pose a risk to public safety.

The Commission and the Authority 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.

3.6.1.4 Transpower

Transpower's interests are identified through the Electricity Industry Participation Code, relationship meetings, direct business communications, annual planning documents, and grid notifications and warnings. Transpower is 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 the national grid including rolling outage plans, automatic under frequency load shedding (AUFLS) and demand side management. These interests are accounted for in WELL'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 WELL'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.

The Kaikoura earthquake in November 2016 caused significant disruption in the region and has highlighted the importance of having a resilient electricity network. This work is further described in Section 11.

3.6.1.6 Industry Organisations

The interests of industry organisations such as Engineering New Zealand, 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 WELL'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, contractual agreements and staff culture surveys. They are primarily interested in a safe and enjoyable working environment, job satisfaction, fair reward for effort provided, mitigation of workplace risks 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 Debt Capital Market Funders

WELL accesses Debt Capital Markets to provide funding support for the investments outlined in this AMP. Banks and investors (through private placement issues) have provided funding to date. Their interests are accounted for in WELL's asset management practices through capital and operational forecasts that enable WELL's risk profile to be understood.

3.6.1.9 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 by regular reporting on 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. WELL will not compromise the safety of the public, its staff or service providers.

WELL is a member of the Utility Disputes Limited (UDL) Scheme, which provides a dispute resolution process for resolving consumer complaints. WELL's Use of System Agreements provides a dispute resolution process for managing conflict with retailers.

3.7 Operating Environment

WELL 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 Legislative and Regulatory Environment

WELL is subject to a range of legislative and regulatory obligations. WELL meets these regulatory and legislative obligations by adopting best practice asset management policies and procedures that underpin this AMP. WELL regularly engages with the Authority and the Commission through participation in working groups, conferences, workshops, consultations on various matters, and regular information disclosures. The legislative and regulatory obligations are detailed below.

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

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, WELL continues to focus on potential safety and environmental risk at the early stages of a project. Risk assessments are conducted with contractors prior to the project being awarded, with continual monitoring throughout the project lifecycle of potential changes in risk. The cost and time implications of this increased focus are factored into project budgets and schedules. WELL also reviews incidents with its service providers on a weekly basis and monitors the effectiveness of controls that are being put in place. Emphasis is placed on ensuring that engineering controls are prioritised ahead of process and administration controls.

The main changes introduced by the HSW Act 2015 that form the primary focus for WELL 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.

The need to consult, cooperate and coordinate between PCBUs has continued to see improvements of the management of the interface boundary with all principal's that do work with WELL.

A compliance management system has been implemented by WELL 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.

3.7.1.2 Price Quality Compliance

WELL is subject to price and quality control contained within Part 4 of the Commerce Act 1986. From 1 April 2018 WELL has been on a CPP for its earthquake readiness programme, which will run until 31 March 2021. As part of the CPP, WELL is also measured against additional performance targets to deliver at least 20%, 40% and 60% of the SCPP Programme at the end of the 2018/19, 2019/20 and 2020/21 years respectively. WELL has completed 65% of the programme as at 31 March 2020. The remainder of the programme will be completed in the 2020/21 year.

3.7.1.3 Information Disclosure

WELL is subject to a range of annual public information disclosure requirements. To ensure accurate preparation and reporting of information, WELL's 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.

3.7.1.4 Default Use of System Agreement (UoSA)

The UoSA agreement provides the terms in which retailers and EDBs contract for the supply distribution services. The Authority and industry are developing a new default UoSA agreement. The default agreement is expected to be finalised in 2020.

3.7.1.5 Pricing Roadmap

WELL has published a pricing roadmap that outlines the development of its distribution pricing over the next 3-5 years. This includes the development of cost reflective pricing options to provide retailers and consumers with clear price signals to encourage off-peak energy use.

3.7.1.6 Government Policy - Major Infrastructure projects

Major infrastructure projects driven by government policy have an impact upon WELL'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.

The NZTA Transmission Gully project is another major project requiring significant work to deviate WELL assets away from the road corridor and to provide new infrastructure to supply street lighting circuits.

The Government announcement of gas exploration curtailment policy from 2050 will impact network capacity as commercial and industrial heat is substituted with electricity.

3.7.1.7 Requirements Driven by Local Authorities

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

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

WELL 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. WELL is required to advise tree owners of their obligations for the safe removal of vegetation. WELL has a Vegetation Management Agreement in place with an external service provider to manage vegetation around the network. WELL's vegetation management programme has resulted in a reduction in the number of tree related faults on the network.

3.7.2 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 retailers. This new technology could also impact consumers, with new markets developing for customers if they choose for their assets to be used for demand management.

The growth of new technologies in the energy storage and market trading environments have a significant effect on the development of smarter electrical networks, and the ability of WELL to influence energy consumption and energy trading. Greater visibility of energy transfer in the form of real time network monitoring and improved digitised data is required to enable WELL to adequately manage this space. WELL continues to monitor evolving technology trends and the uptake of new technology that is likely to impact on the electricity sector. This includes (but is not limited to) monitoring the uptake of commercial and residential solar panels (Photovoltaics or PVs) and energy storage systems, the increasing penetration of EVs in New Zealand's vehicle fleet, and the applicability and use of technology for network monitoring, design and operation. While the rate of uptake is uncertain, technology is likely to have an increasingly significant impact on consumer behaviour as EVs, PVs, and battery storage become more affordable.

There is uncertainty about the impact that new technology will have, with some technology increasing energy transferred (e.g. EVs), while others will reduce energy transferred (e.g. PV).

Industry changes required to enable the introduction of this new technology include:

- New technology standards: Introduce new standards for new technology, allowing better and lower cost integration;
- Mandatory notification: Require customers who want to install new technology to apply to their lines company. This will ensure that the installation of the new technology complies with the standards of the network for two way power flows;
- Congestion standards: Introduce standards on how congestion is defined and require network congestion to be disclosed;
- Low voltage monitoring: Improve the monitoring of the network particularly LV with DERs where current monitoring is inadequate and where changes are most likely to be felt;
- Management of distributed resources: Investigate and trial a platform that enables the management of distributed energy resources;
- Support with efficient prices: Introduce efficient prices that reflect the benefits and encourage the use of disruptive technology;
- Smart meter data: Require LV data to be made available to the supply chain. This will provide EDBs visibility of the LV network, allowing them to manage demand effectively and to calculate efficient prices for services using disruptive technology; and
- Available funding: Ensure that funding is available to develop and implement the new technology.

Regulatory support is required to ensure these changes can be implemented.

As well as working with industry and regulators to ensure these changes are implemented in the short term, WELL continues to learn from others and to trial new technologies to further learn and prepare for the changes ahead. WELL believes testing new technology through trials is a prudent and flexible approach to manage the uncertainty associated with new and emerging technology, while avoiding the risk of overbuild in the short term. It is WELL's view that new technology will enable the monitoring and management of the LV network, and working closely with other industry participants will deliver the best long term solution for New Zealand.

WELL will continue to utilise its position as part of the CK Infrastructure Holdings Limited group to leverage experience with new technology from its global sister companies. This provides WELL with unique access to intellectual property and resources from across the globe. In addition, WELL collaborates with local EDBs to draw on the New Zealand specific experience within the emerging technologies market.

3.7.2.1 Electric Vehicles

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:

- 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;
- New Zealand's high level of renewable energy generation (over 80%) being an ideal match for EVs which are seen as an appealing option for environmentally and cost-conscious consumers; and
- Constantly evolving energy storage systems, electric drives and charging technologies that will improve the efficiency and range of EVs.

To ensure consumers are able to make informed choices around new technology, WELL has published cost reflective prices which signal the times that the network is more congested, and thus more expensive to use. This will enable customers to save money by using the network at less congested periods.

WELL supports the electrification of transport as a significant means of reducing carbon emissions. Following the expiration of the agreement to supply the electric trolley bus network, WELL is working with the regional and city councils on new technology opportunities to continue electric public transport services in Wellington.

Large fast charging requirements may require consideration of network storage versus traditional upgrades to infrastructure capacity. The need to provide temporary generation to maintain lines de-energised is also expected to transfer across to battery storage support rather than the traditional fossil fuel generation. Ideally both initiatives can be combined so support as a service can augment the network to defer more traditional asset capacity investment. The development of these new technologies will require that WELL has access to information to enable the bi-directional transfer of energy safely, reliably and cost effectively.

The WELL network already has features which allow for "smarter" 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 WELL control room;
- On demand load management via the existing ripple control system; and
- High voltage network modelling and step change load impact analysis to ensure assets are operating within the design limits.

3.7.3 The Financial Environment

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

WELL is currently on a CPP which expires 31 March 2021. WELL will then move to the DPP that most other price/quality regulated EDBs operate under. WELL regularly reviews which regulatory model is most appropriate, balancing the low cost simplicity of a DPP against the ability of funding large capital programmes under the CPP.

Funding for innovation projects is available from Government initiatives such as the Low Emission Vehicle Contestable Fund (LEVCF). There is also an allowance of 0.1% of allowable revenue included in DPP3 for the part funding of projects to develop or deploy new technologies that reduce cost or increase quality for customers. It is expected that application mechanisms under Part 4 Clause 54Q of the Commerce Act 1986 could be exercised around energy efficiency by making particular new technology investments affordable under current allowances for traditional network operation and maintenance.

WELL is continuing to manage its financial performance in a prudent manner, ensuring expenditure is targeted at the highest priorities and maintaining the quality of supply under the price quality framework.

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

Section 4
Frameworks
(Asset Management, Safety and Risk)

4 Asset Management, Safety and Risk Frameworks

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

- The asset management framework;
- The investment selection process;
- The asset management delivery process;
- Asset management documentation and control;
- The Asset Management Maturity Assessment Tool (AMMAT);
- Quality, safety and the environment (QSE); and
- Risk management.

4.1 Asset Management Framework

WELL's asset management framework is aligned with the company's vision, mission, corporate strategy 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 shown in Figure 4-1.

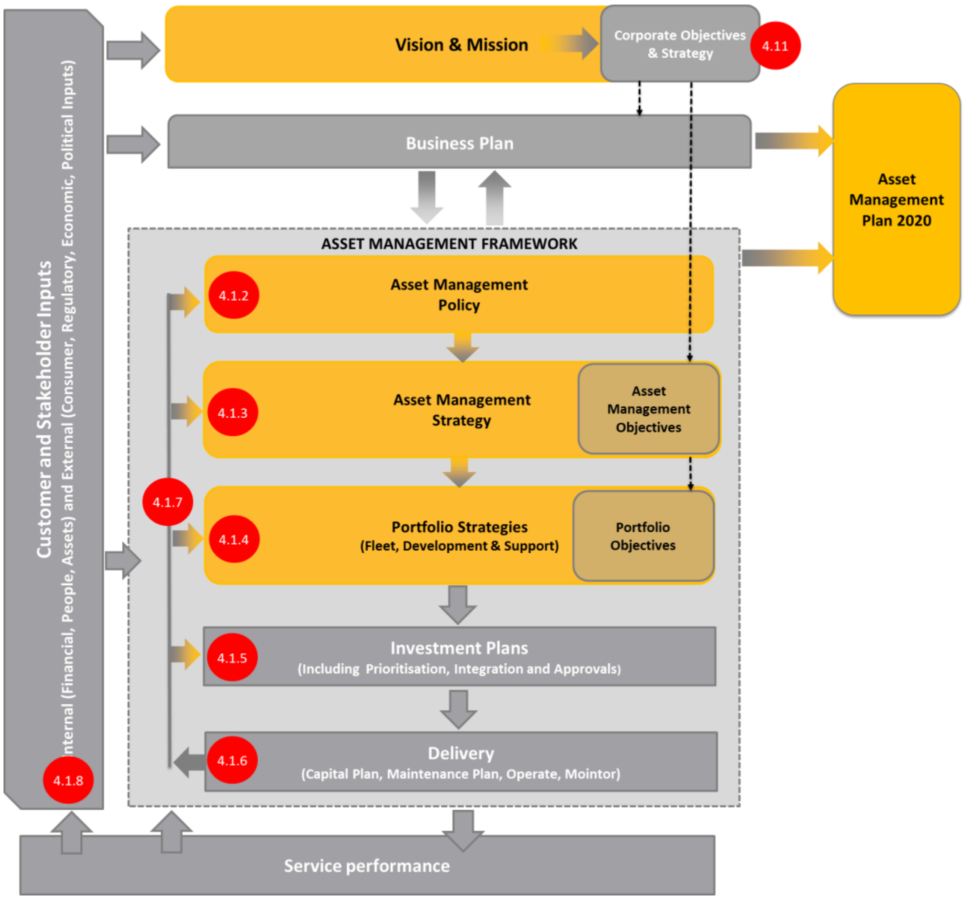


Figure 4-1 Asset Management Framework

WELL's asset management approach provides a clear 'line-of-sight' between the company's mission, investment plans, how services are delivered and customer preferences. A high level summary of each major component of the Asset Management Framework is discussed in the following sections. Each section is referenced in the figure above.

4.1.1 Corporate Objectives

WELL's Corporate Objectives are expressed through its Corporate Mission and Values. They include the company performance objectives (including annual KPI's) and feature the company's safety, quality targets (both SAIDI and SAIFI) and customer service targets.

4.1.2 Asset Management Policy

The asset management policy establishes the formal authority for asset management within WELL.

It aligns with the company'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".

The scope of the policy covers all the assets owned and operated by WELL for the purposes of providing electricity distribution services.

The objective of the policy is "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 WELL'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;
- Aligns with the risk management framework;
- Assists with the development of staff capabilities and the engagement of external resources when required to continually improve asset management capability; and
- Provides a suitable long-term return on investment for shareholders.

4.1.3 Asset Management Strategy and Objectives

WELL's Asset Management Strategy builds on the Asset Management Policy to ensure a clear 'line of sight' between the corporate objectives and the asset management objectives. WELL has identified five priority areas along with their associated key objectives:

- Safety and Environment: People, public and the environment are kept safe
- Customers: We provide an excellent service to our customers that matches their needs
- Network Performance: Provide a network that delivers to our customers' needs now and in the future
- Cost: Long term profitability driven by efficiency and innovation
- Capability: Continuous development to deliver performance and efficiency improvements

The Asset Management Strategy summarises the objectives and strategies in each of these five priority areas. The first four priority areas relate to aspects of WELL's performance. The fifth priority area relates specifically to asset management capability, which supports the other objectives. Sections 5 and 6 provide more detail on specific asset management objectives and strategies associated with these priority areas.

4.1.4 Portfolio Strategies

Portfolio strategies translate the Asset Management Strategy into specific strategies for each portfolio, link back to the objectives in the Asset Management Strategy, and detail any fleet-specific objectives. These portfolio strategies include asset fleet strategies, network development strategies, emerging technology, support systems, resilience, and customer initiated projects and relocations, which are discussed in Sections 7 to 12 respectively. Each strategy is used to develop Network Standards, work plans and programmes which include the activities and budgets presented in the 10 year AMP and five year business plan.

4.1.5 Investment Planning

WELL's investment plans are developed from the individual portfolio strategies. Investment planning includes integration, prioritisation and approval processes to ensure prudent financial investment. Investment planning is discussed further in Section 4.2.

4.1.6 Delivery

There are two components to delivery: delivery of the investment plans and management of the network in real time. The delivery of investment plans to meet the target customer service levels is discussed in Section 4.3.

The objective of WELL's real time network management is to manage the network safely and, when outages occur, to restore power safely and as quickly as practical, minimising the impact of outages on customers. WELL's outage management process is detailed in the Fault Restoration Standard.

4.1.7 Internal Feedback Loops

Essential inputs to each component of the Asset Management Framework include asset condition, network performance, and customer feedback. Performance reporting is provided to those responsible for each component of the Asset Management Framework, creating internal feedback loops within the framework. Each strategy and plan is refined and adjusted in response to the performance measures and customer feedback.

4.1.8 Stakeholder and Customer Inputs

Customer feedback is essential to ensuring that WELL is providing the services that customers want and at a level of quality they are willing to pay for. WELL regularly surveys its customers about whether they are happy with the current service quality. WELL also meets with community groups to test the balance between price and quality and/or to engage with customers in relation to topical events and issues which may be relevant to them. WELL's customers have consistently said they support current quality levels and do not want to fund a quality improvement. The Asset Management Framework reflects this by targeting reliability performance at current levels.

4.2 The Investment Selection Process

The investment selection process has five generalised stages, as illustrated in Figure 4-2.

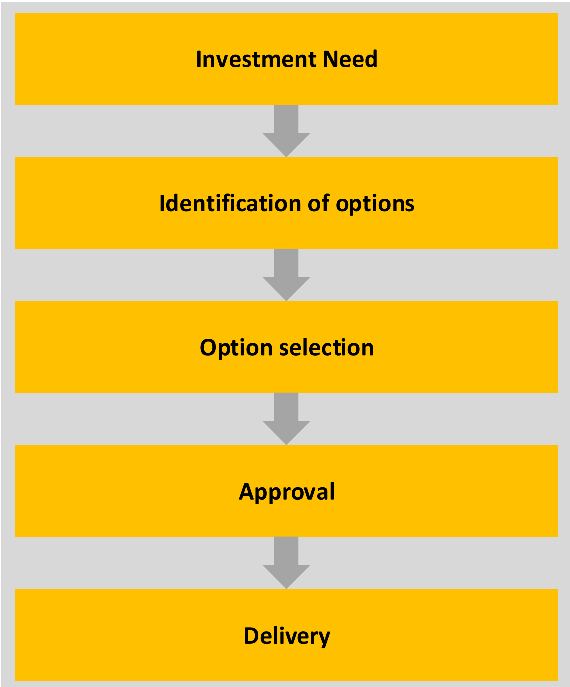


Figure 4-2 Investment Selection Process

4.2.1 Need Identification

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

4.2.1.1 Risk-based Approach

WELL takes a risk-based approach to "need identification". Management of risk is fundamental to the 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 by meeting security of supply criteria standards, capital and maintenance work programmes, enhanced working practices and the development of fleet strategies. The development of these strategies includes root cause analysis from the growing database of asset failure information, and predicts future corrective maintenance expenditure over time; and

- Reactively: Reducing the impact of a failure through business continuity planning and the delivery 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 immediate safety impact of the failure, the magnitude of any supply interruptions, any environmental consequences, 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 to allow it to continue in service, supported if necessary by additional inspection and preventative maintenance activities.

4.2.1.2 Prioritisation of Projects

The AMP 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.

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

Non-discretionary projects include:

(i) HSE and Legal Compliance. WELL'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 WELL 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.

4.2.2 Option Identification

Various options are identified and considered to address the investment need. These include:

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

These investment options are considered to ensure the overall service levels sought by all stakeholders are achieved within regulatory allowances to balance the price/quality trade off. This is to align reliability with the cost that customers pay over the long term.

4.2.3 Option Selection Process

The option selection process describes the way in which network investments are taken from a list of appropriate options, refined to a short list of practicable options followed by detailed analysis and selection of a preferred option which is then documented in a business case for approval. The Works Plan is the repository for all network investments for the year ahead and includes projects funded solely by WELL as well as other customer-funded projects. The Works Plan is consistent with the first year of the AMP.

The process is as follows:

1. Outputs from the option identification process are developed into a business case, justifying the need for investment and recommending the preferred option.
2. Approved recommendations are entered into the draft Works Plan and prioritised in terms of safety, customer needs, budget, timelines and network criticality.
3. The Works Integration team develops, prioritises and allocates budget for the annual Works Plan based on a totex approach which combines and integrates capex and opex requirements to gain efficiency and effectiveness from service providers.
4. Following final prioritisation, a list of projects for the following year (i.e. the Works Plan) is prepared to inform the annual budget which is submitted for management approval and recommendation to the Board for approval.

4.2.4 Investment Approval

Investments are approved according to WELL's DFA structure which is described in Section 3.2.4.

4.3 Asset Management Delivery

The Works Plan is the repository for all network investments for the year ahead. It is used as the final document for tracking all network capital projects to be delivered for the year. Once approved, the Works Plan is managed by the Service Delivery team, with progress reported to the Executive and the Board.

4.3.1 Field Delivery

WELL utilises an outsourced 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, Connetics etc.;
- Vegetation management – Treescape; and
- Contact centre – Telnet.

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

The services provided are described in further detail below.

4.3.1.1 Fault Response, Maintenance and Minor Capital Works

Northpower Ltd has been WELL's primary field service provider responsible for fault response and maintenance since 2011. In 2018 WELL ran a contestable process for a new field services contract. Northpower was successful and have been contracted as the field services provider under a new Field Services Agreement (FSA) through to 2023.

The FSA delivers a number of strategic outcomes for WELL. It is structured to ensure alignment with WELL's asset management objectives and to improve the integrity of the asset data held in WELL'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, critical cable standovers during excavation, and provision of buried asset plans provided to third parties;
- Minor connection services and livening; and
- Management services – 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 regular meetings to cover off key functional areas between WELL and Northpower.

4.3.1.2 Contestable Capital Works Projects

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 competitively tendered. They are delivered under either independent contractor agreements (ICAs) or the FSA if Northpower is the successful tenderer. These agreements outline the terms and performance requirements the work is to be completed under and include KPIs or KRAs, defects liability periods, insurance and liability provisions, and also reflect the requirements of the HSW Act. 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.

4.3.1.3 Vegetation Management

This outsourced contract for vegetation management was also tendered competitively in 2018 with Treescape being successful with a new contract being awarded. The contract provides for vegetation management as per the Tree Regulations, as well as improving landowner awareness of tree hazards.

Management of this contract is the responsibility of the General Manager Service Delivery in a similar manner to the Northpower FSA with regular meetings and performance incentives in place.

4.3.1.4 Contact Centre

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.

4.4 Asset Management Documentation and Control

WELL 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 and reinforcement 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, specifications, drawings, operations and maintenance standards, and guidelines follow the structure of the controlled document process, with a formalised review and approval process for new and substantially revised documents. The documents are made available via intranets and extranets 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.

4.5 Asset Management Maturity Assessment Tool (AMMAT)

The AMMAT is a self-assessment questionnaire based on PAS55 Assessment Methodology. There are six assessment areas, each focusing on the way that the organisation manages either its processes or its people:

- Asset strategy and delivery;
- Communication and participation;
- Competency and training;
- Documentation, controls, and reviews;
- Structure, capability and authority; and
- Systems, integration and information management.

WELL's Asset Management Maturity Assessment is provided in Appendix C. The graph in Figure 4-3 gives a summary of the results.

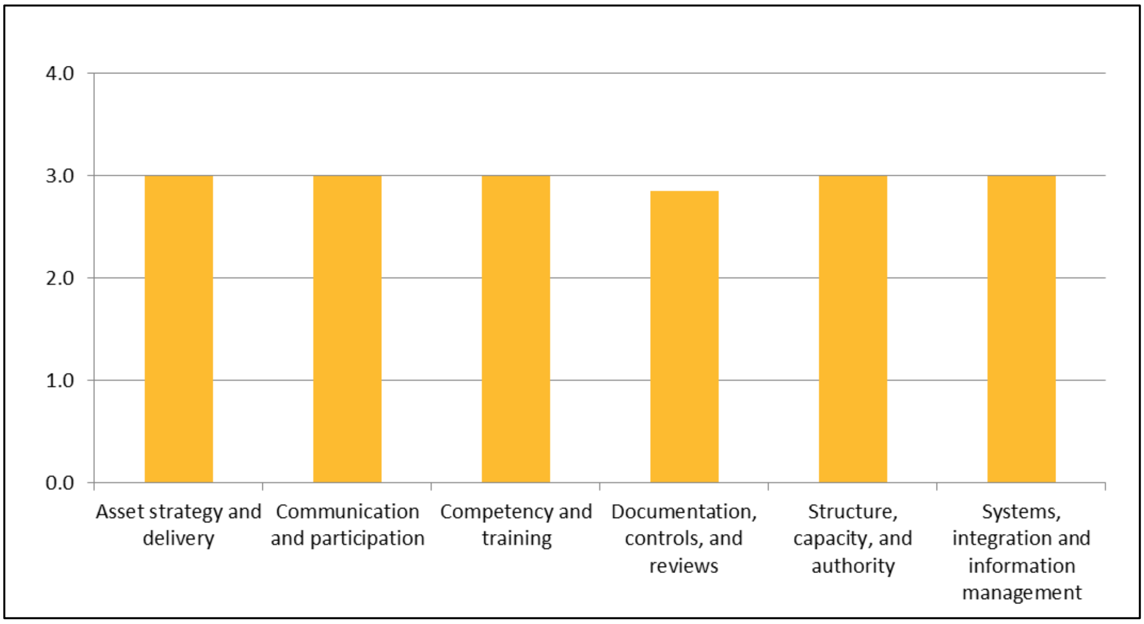


Figure 4-3 Summary of the Maturity Assessment 2020

A minor gap identified was in the area of continual improvement, in the systematic application of risk forecasting across all Assets Fleet Strategies, as detailed in Table 4-1.

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?	The Asset Fleet Strategies detail asset-specific strategies for meeting the asset management objectives. These documents analyse the performance, and condition of assets across the whole life cycle, as well as maintenance and replacement costs, and any associated asset-related risks. They are controlled documents on an annual review cycle, with this update process ensuring that continual improvement in the management of asset performance, condition, costs, and risks. Completion of the remaining strategies is required to achieve Maturity Level 3.	Complete remaining Fleet Strategies during 2020, to ensure the continuous improvement process is systematically applied across all fleets.

Table 4-1 Strategies for Improving Asset Management Maturity

Development of areas beyond Maturity Level 3 for individual aspects of the AMMAT will be considered by WELL where the need is clear, cost effective and justifiable.

4.6 Quality, Safety and the Environment (QSE)

WELL is committed to provide excellence in QSE outcomes through application of the following principles:

- Members of the public are not harmed by the operation, maintenance and improvement of WELL's assets;
- All employees and contractors undertake their work in a safe environment using safe work practices;

- The wellbeing (physical and mental) of staff and field workers is a key focus;
- Controls, such as policies, plans, and competencies are effective for minimising impacts to the environment;
- Processes such as audit and review procedures are in place to ensure high quality outcomes are consistently achieved; and
- Continuous improvement is a key goal.

To support these principles, WELL maintains a comprehensive set of health and safety, environmental, and quality policies and procedures which, together with the wider business policies and standards, are routinely reviewed and updated.

In accordance with WELL's mission, health and safety is given top priority and is a core business value. A Board Health and Safety Committee meets regularly to be updated on issues and to provide guidance to management. As illustrated in Figure 4-4, a formalised safety leadership structure is in place to help ensure that health and safety leadership is provided throughout the business.

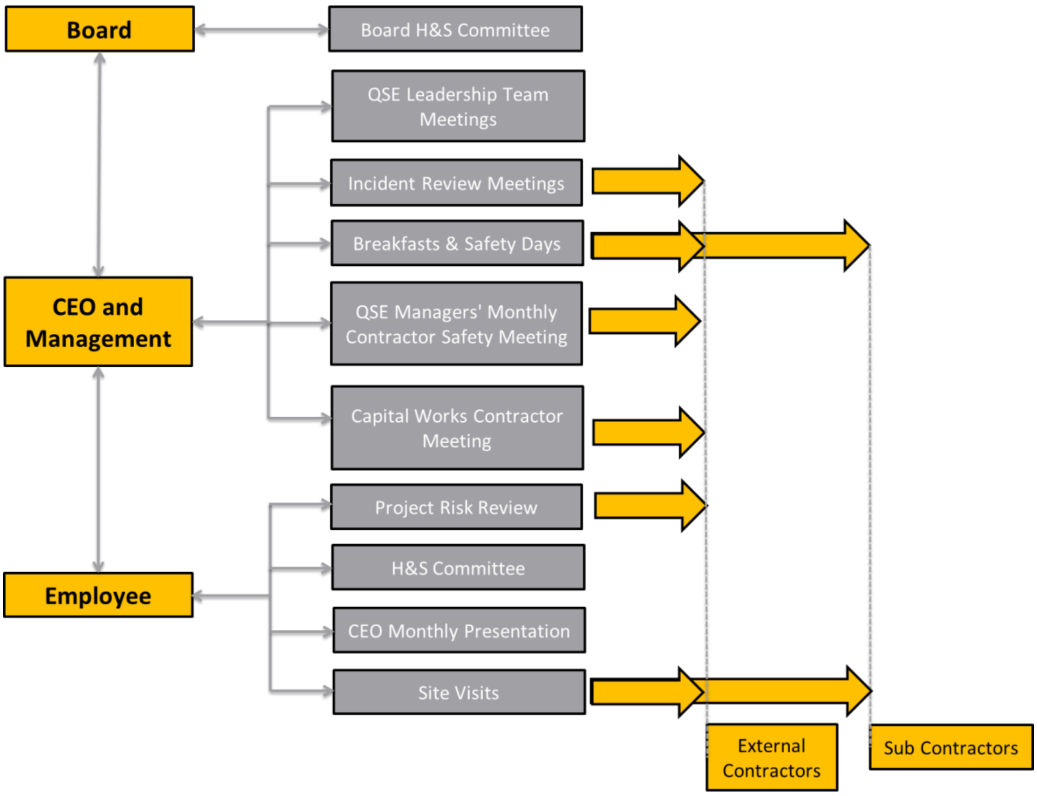


Figure 4-4 WELL's Safety Leadership Structure

WELL holds a monthly Safety Leadership Committee (QSE Leadership Team) meeting to monitor performance, discuss emerging trends or new issues and progress on key improvement areas. The CEO and general managers are part of the QSE Leadership team. WELL employees and contractors work together via a process involving consultation, collaboration and coordination to help deliver safe work practices, make appropriate use of plant and equipment (including protective clothing and equipment), and review that controls are being managed and report on incidents, near misses and hazard observations.

In a similar manner, quality and environmental outcomes are managed by WELL via consultation, co-operation and co-ordination. All employees and contractors are required to:

- Take all reasonable steps to ensure that business activities provide an outcome that minimises environmental impacts and promotes a sustainable environment for future generations;
- 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; and
- Identify and report any defects or non-conformances to enable improvement in the systems or performance to maintain quality outcomes.

WELL's QSE outcomes and processes are discussed in more detail below. The associated performance objectives and measures are described in Section 5.

4.6.1 Safety Regulation

WorkSafe New Zealand (WorkSafe) is the work health and safety regulator. Worksafe's functions include:

- Monitoring and enforcing compliance with work health and safety legislation;
- Providing guidance, advice and information on work health and safety; and
- Compliance to the Health and Safety at Work Act 2015.

The Health and Safety at Work Act 2015 (HSW Act) came into effect in 2016. Consistent with the HSW Act, WELL continues to develop closer relationships with other organisations and stakeholders where an interface with network assets exists. The HSW Act requires a greater level of consultation, co-operation and co-ordination in relation to health and safety duties and issues. This brought about a number of changes in the way WELL conducts its outsourced field activities. 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. 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.

4.6.2 Public Safety Management Systems (PSMS)

WELL has a Public Safety Management System (PSMS) framework, built on policies, procedures and guidelines relevant to the safe design and management of the assets. The PSMS helps ensure that assets installed in public areas 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 NZS 7901:2008 Electricity and gas industries - Safety Management Systems for Public Safety. The certification body Telarc reassessed WELL against the requirements of NZS 7901 in 2018 and confirmed that WELL was compliant with regulatory requirements.

WELL continues to invest significant resources to raise awareness in the community of the potential risk of living and working near electricity assets. WELL provides public 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. It 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.

4.6.2.1 School Safety Programme

WELL 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. 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, which contains interactive safety games and information targeted at young children and parents regarding network safety and electrical safety around the home. There is also a link to the website in the School Safety Programme section of WELL's website.

4.6.2.2 Media Advertising

WELL actively raises public awareness about the dangers of living and working around network assets. WELL 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 2019 relating to vegetation management, excavation safety and safety disconnections for maintenance around the home.

4.6.2.3 Safety Seminars and Mail Outs

In order to help prevent third party contact with the network, WELL works closely with civil contracting companies (third party contractors working around WELL 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 WELL mails out letters to various contracting sectors focusing on infringements impacting safety around the network.

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

4.6.2.4 Contractors' Safety Booklet

WELL has produced a safety publication targeted at civil contractors and those working near, but not accessing, the WELL network. This booklet *"we* all need to work safely"*, last revised in February 2020, is handed to those attending safety workshops and in mail outs to various contracting sectors that interface with the network.

4.6.2.5 Information and Value Services

WELL 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.

This includes services such as:

- Service Map requests
- Cable Locations
- Close Approach
- Standovers
- High Load Permits
- High Load Escorts

Since 2012 there has been a significant increase in calls relating to service map requests. The increase is attributed primarily to the UFB rollout in the Wellington region.

The additional risk created by the extra work around WELL poles is being carefully managed in terms of the HSW Act by formal contractual conditions and consultation, co-operation and co-ordination between parties involved in the UFB installation work.

4.6.3 Workplace Safety and Initiatives

WELL has the following workplace safety initiatives in place.

4.6.3.1 Staff Health and Safety Committee (H&S Committee)

The H&S Committee represents WELL's employees and meets bi-monthly to address issues raised by Workgroup Representatives or reported through WELL's Health and Safety Management System (1FiCS). The H&S Committee is made up of seven volunteers and deals with concerns ranging from Emergency Preparedness & Response to faulty appliances that need repair or replacement.

4.6.3.2 Safety Breakfasts

WELL 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 publicly recognise and celebrate examples of good safety behaviour and practice. On average 300 people are catered for at these sessions.

4.6.3.3 Annual Worker Safety Workshop

WELL 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 WELL's desired behaviours through direct interface with keynote speakers and other subject matter experts.

4.6.3.4 Site Safety Visits

All WELL staff undertake engagement 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.

4.6.3.5 Workplace Safety Training and Competence

WELL 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.

WELL ensures its personnel are trained and competent in safety matters through providing, for example:

- CPR / First Aid refresher sessions every six months;
- Work Type Competency (WTC) Training;
- Restricted area access training;
- Defensive driving training; and
- Basic Traffic Control management.

4.6.3.6 Incident Review Meetings

WELL holds weekly internal meetings involving the outsourced service providers to review and address reported hazard observations, near misses and incidents. A key objective of these meetings is to prevent incidents occurring or recurring, and to use lessons learnt for continuous improvement.

4.6.3.7 Safety Alerts

When the need arises, WELL issues Safety Alerts to all its service providers highlighting a safety concern and listing any actions required to reduce the concern.

4.7 Risk Management

WELL aligns its risk approach with that of its parent company by adopting the Enterprise Risk Management (ERM) – Integrated Framework Risk Management – Principles and Guidelines standard. This provides a structured and robust framework to managing risk, which is applied to all business activities, including policy development and business planning. WELL's risk management framework is discussed in Section 4.7.2.

Risk management is an integral part of good asset management practice. WELL's approach to managing asset-specific risks is discussed in Section 7.

4.7.1 Risk Management Accountabilities

WELL'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 three times a year by the CEO as part of the regular management reporting functions. This is 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. 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 for controls is 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 4.7.3.

4.7.2 Risk Management Framework

WELL's approach to risk management is illustrated in Figure 4-5.

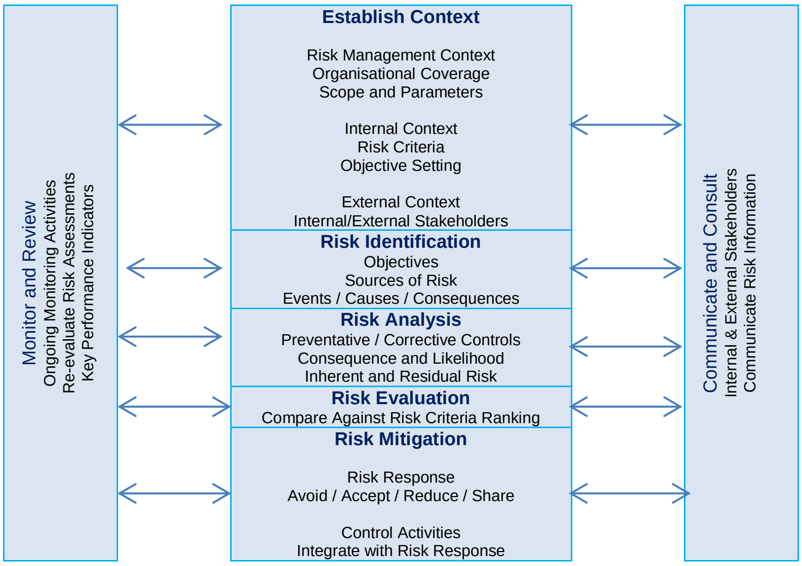


Figure 4-5 WELL's Risk Management Process

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

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

Risk Identification. Risks are identified through operational and managerial processes. WELL has grouped its risk into seven categories. Section 4.7.3 describes the controls used to mitigate the risks. The seven categories of risks 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). Where applicable, the consequence and likelihood tables have been developed to deliver WELL's asset planning objectives. Consequence scales reflect levels of consequence for each criteria ranging from extreme (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. The risk profiling matrices shown in Figure 4-6 are used to determine the level of the risk or risk rating.

LIKELIHOOD	CONSEQUENCE				
	Minimal	Minor	Moderate	Major	Extreme
Almost Certain	Medium	High	High	High	High
Likely	Medium	Medium	High	High	High
Possible	Low	Medium	Medium	High	High
Unlikely	Low	Low	Medium	Medium	High
Almost Never	Low	Low	Low	Medium	Medium

Figure 4-6 Qualitative Risk Matrix

Risk Evaluation. Requires the evaluation of risk likelihood and consequence by assessing the results of a risk analysis. This evaluation of risk is used to identify controls that could be put in place to mitigate the risks identified and the priorities of each risk mitigation strategy.

Risk Mitigation. Risk mitigation utilises controls to mitigate the risk. Controls can include procedures and processes that eliminate or isolate the risk source, changing the likelihood and consequence of the risk occurring, sharing the risk with another party or parties (e.g. contracts and insurance), and/or accepting the risk by informed decision. Controls mitigate the likelihood or consequence of the risk which reduces the inherent risk score to give a residual risk rating.

4.7.3 Key Business Risks and Controls

Rankings of risk events and control effectiveness were updated in December 2019, identifying no current extreme residual risks and only one high residual risk.

In total, 45 business risks were assessed by WELL. Table 4-2 shows the 10 highest risks ranked according to their residual ratings, and then by their inherent risk ratings.

	Event	Inherent Rating	Residual Rating
1	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets.	High	High
2	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.	High	Medium

	Event	Inherent Rating	Residual Rating
3	Non-optimum starting price adjustment.	High	Medium
4	Taxation authorities dispute Business' position on tax treatments.	High	Medium
5	Exploitation of IT security.	High	Medium
6	Injury or Damage caused or loss suffered to third parties.	High	Medium
7	Sub-optimal performance or failure of network assets.	High	Medium
8	Non-compliance with Electricity Act and Regulations.	High	Medium
9	Non-compliance with the Health and Safety at Work Act 2015.	High	Medium
10	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources).	High	Medium

Table 4-2 Summary of 10 Highest Business Risks

The business identified over 200 unique controls that aim to mitigate the causes and consequences across the identified risks. The 10 most frequently used controls for managing risk across the business are:

- Insurance process including engagement of qualified brokers;
- Board and Board Committees and Reporting Structure;
- Contractor Management System and Processes
- Auditing and Compliance (external and internal);
- Management Monitoring, Reporting and Review;
- Purchasing and Procurement Policy and Processes;
- Asset Management Policies, Strategies, Standards, and Plans;
- Education, Training and Development Policies and Programs;
- Delegations of Financial Authority; and
- Incident reporting and Investigation processes and standards.

4.7.3.1 Insurable Risks and Insurance Premiums

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

The balance (85% by replacement value) of WELL's network is not insured. As such, the customer retains the risk on the uninsured portion of the network. WELL would have to apply for a CPP following a significant event to request additional funding (and an associated price increase) to repair the network. WELL does not insure its subtransmission and distribution assets 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.

Illustrating this by way of example, if WELL 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 range of $40 million to $50 million. This additional cost would be passed onto consumers via line charges and is not considered economic. Ex post recovery of the full costs is therefore the regulatory recovery mechanism for managing this risk.

4.7.3.2 Insurance Cover

WELL 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.

Section 5

Service Level

5 Service Levels

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

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

The Reliability Performance objectives and strategies are discussed in greater detail in Section 6.2 separately to the rest of the other Service Levels due to the complexity and detailed discussions included. The service levels also incorporate feedback received from the stakeholder groups discussed in Section 3.6.

5.1 Safety Performance Service Levels

WELL 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 WELL and involves ongoing review of health and safety practices, systems and documentation.

WELL welcomes the Worksafe New Zealand legislation as an ongoing approach of continual improvement to workplace safety and a focus on effective identification and management of risk to protect the welfare of workers engaged in delivering services, and the safety of the public.

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

- Incident, near miss and hazard observation reporting;
- Corrective actions from site visits closed;
- Lost Time Injury Frequency Rate (LTIFR); and
- Total Notifiable Event Frequency Rate (TNEFR).

LTIFR and TNEFR are lagging indicators of safety performance, while hazard observation 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.

5.1.1 Lost Time Injury Frequency Rate

WELL's staff and contractors recorded zero Lost Time Injuries (LTI) incidents in the industry reporting year ending June 2019. This resulted in a LTIFR for that period of 0.00 per million hours worked and a two year rolling average of 0.00 per million hours worked. The trend in LTIFR is shown in Figure 5-1.

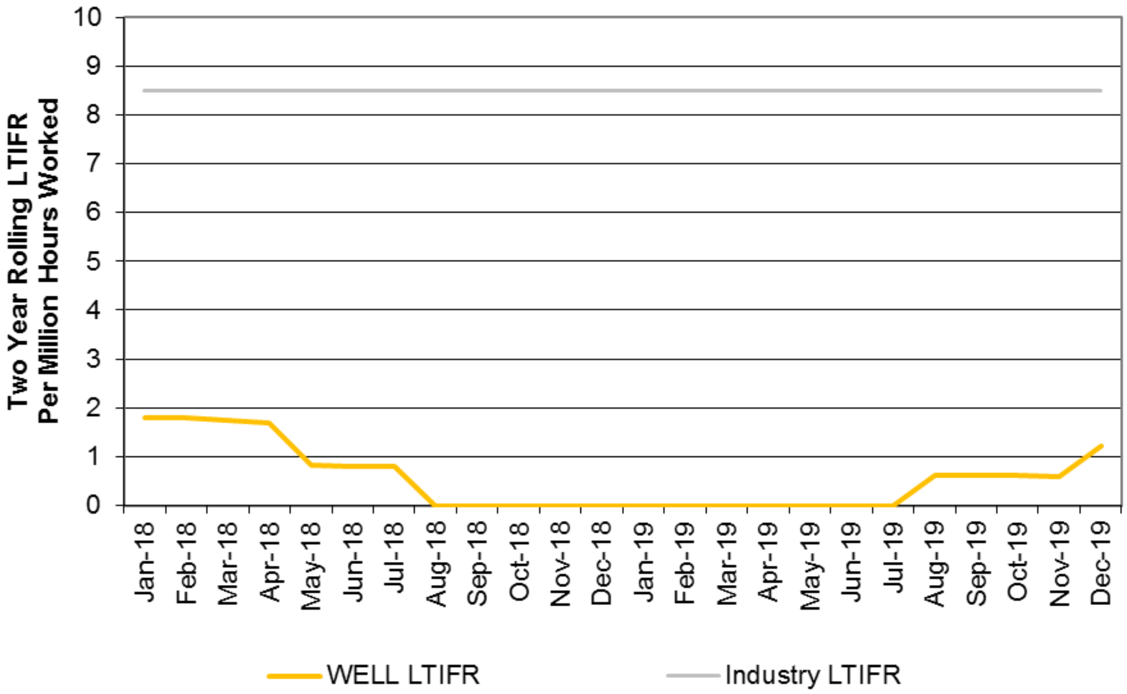


Figure 5-1 Lost Time Injury Frequency Rate

5.1.1.1 Planning Period Target

WELL's target for the 10-year planning period is to achieve a zero LTIFR over the whole period.

5.1.2 Total Notifiable Event Frequency Rate

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

This is a lagging performance measure that commenced in 2016 and is now included in all service provider performance indicators.

WELL's staff and contractors recorded one Notifiable Event in 2019. This resulted in a 2019 TNEFR of 1.27 per million hours worked and a two year rolling average of 3.11.

5.1.2.1 Planning Period Target

WELL's target for the 10 year planning period is to achieve a zero TNEFR over the whole period.

5.1.3 Incident and Near Miss Reporting

During 2019 WELL continued to implement initiatives aimed at increasing reporting rates of hazard observations and near miss events. Increased reporting is a measure of a mature safety culture and allows for continuous improvement from small incidents which in turn reduces the likelihood of serious events.

Total event reporting in 2019 was 583 events reported. Approximately 93% of all reported events were classified as minor, 4% were classified as moderate, whilst 0% were of a serious nature. The total number of proactive reports received during 2019 was 195, an improvement on the previous year's proactive reports. These 195 are further broken down to 29 near miss events and 169 hazard observation reports.

5.1.3.1 Planning Period Target

WELL's current expectation for the 10 year planning period is to maintain the number of addressed hazard observation events reported per annum to approximately 200.

5.1.4 Corrective Actions from Site Visits

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

There has been a decrease in the ratio of corrective actions identified per assessment against 2015 levels, as shown in Figure 5-2. Monitoring continues to help ensure that this trend is continued. A focus in 2017-2019 was compliance with temporary traffic management requirements and public safety around worksites.

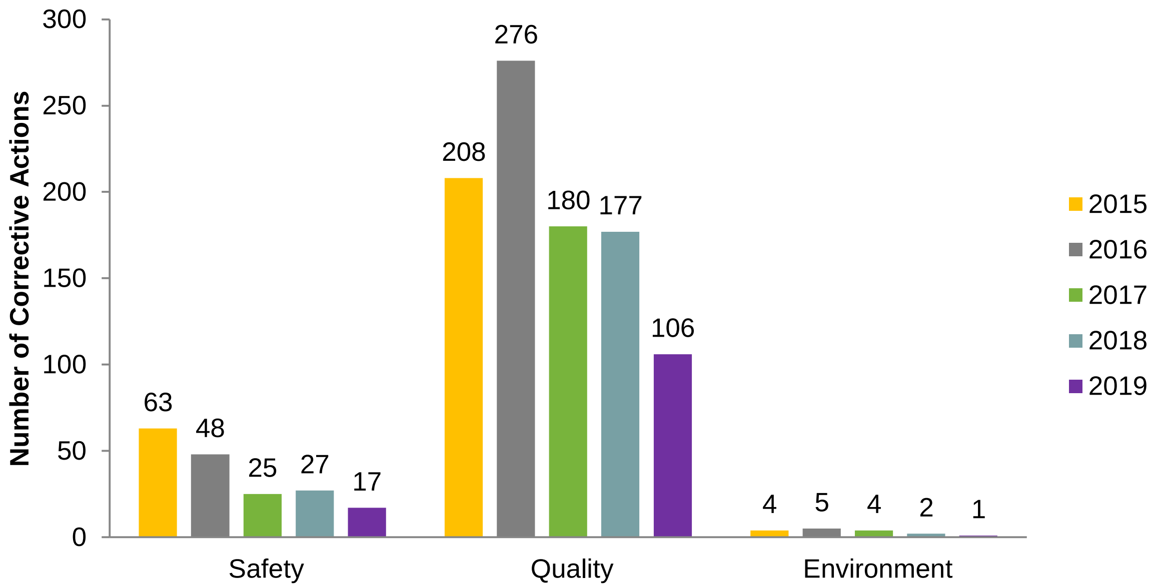


Figure 5-2 Corrective Actions arising from Assessments 2015-2019

5.1.4.1 Planning Period Target

WELL's target for the 10 year planning period is to maintain the current level of field compliance assessments of approximately 400 assessments per year while reducing all three types of corrective actions.

5.1.5 Health and Safety Initiatives

During 2020 focus will be placed on the following areas to further improve performance:

- Reinforcement of WELL's safety brand "safer together";
- Increased emphasis on the wellbeing (physical and mental) of staff and field workers via focussed programmes and engagements;
- Maintain the timeliness of close-out of assessments;
- Reinforce the application of the risk management framework and expand the risk assessment process with clear focus on critical risk and control management and principal/contractor communications;
- Maintain site visits to further engage and consult workers on safety culture and supportive behaviours;
- Continue to expand the consultation, coordination and cooperation where work involves overlapping PCBU duties; and
- Increase strategic risk collaboration with contracted field service providers in development of practical and effective risk controls.

5.2 Reliability Performance

5.2.1 Reliability Measures

Network reliability is measured using two internationally recognised performance indicators, SAIDI[16] and SAIFI[17]. When taken together SAIDI and SAIFI indicate the availability of electricity supply to the average customer connected to the network.

- 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. It is measured as a number of interruptions[18].

In accordance with the methodology established by the Commission, the following supply interruptions are not included in the measured performance indicators:

- Interruptions caused by the unavailability of supply at a GXP, as a result of automatic or manual load shedding directed by the transmission grid operator[19], or as a result of some other event external to the WELL network;
- Interruptions lasting less than one minute. In these cases restoration is usually automatic and the interruption will not be recorded for performance measurement purposes. However these interruptions are recorded by WELL to understand customer service and for planning and operational purposes; and

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[16] System Average Interruption Duration Index

[17] System Average Interruption Frequency Index

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

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

- Interruptions resulting from an outage of the low voltage network or a single phase outage of the 11kV distribution network. In practice such interruptions do not have a material impact on measured system reliability.

The SAIDI and SAIFI targets against WELL's historical performance are shown in Figure 5-3 and Figure 5-4. The 2019/20 year includes a forecast to account for the March 2020 month shown in dark blue.

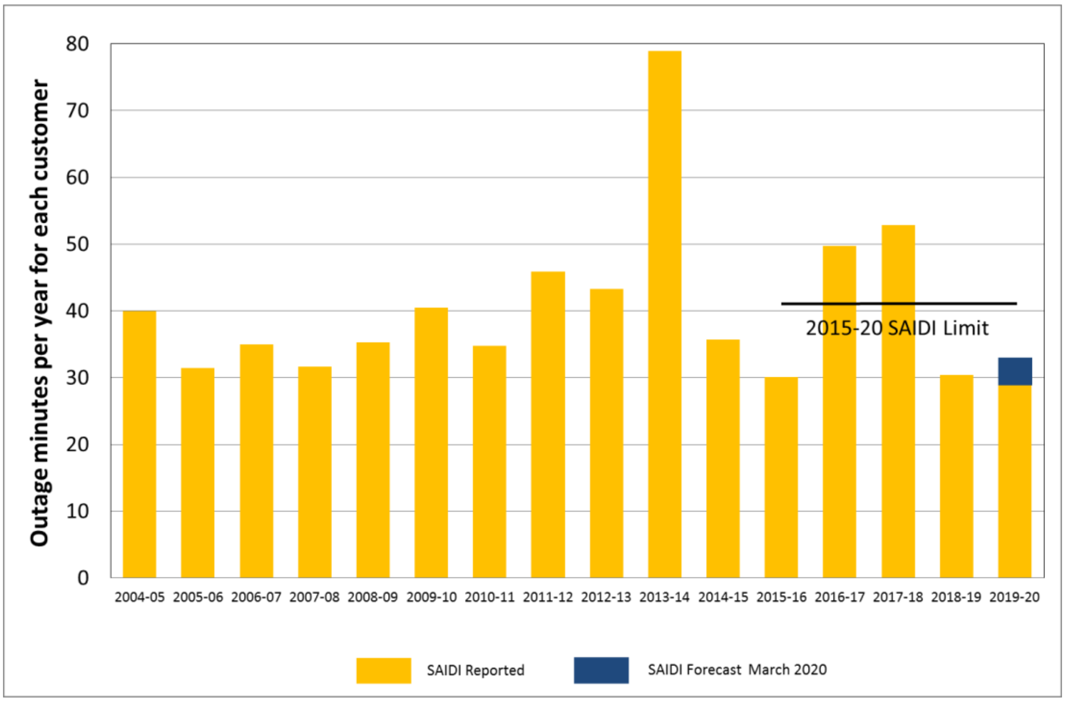


Figure 5-3 WELL SAIDI Performance

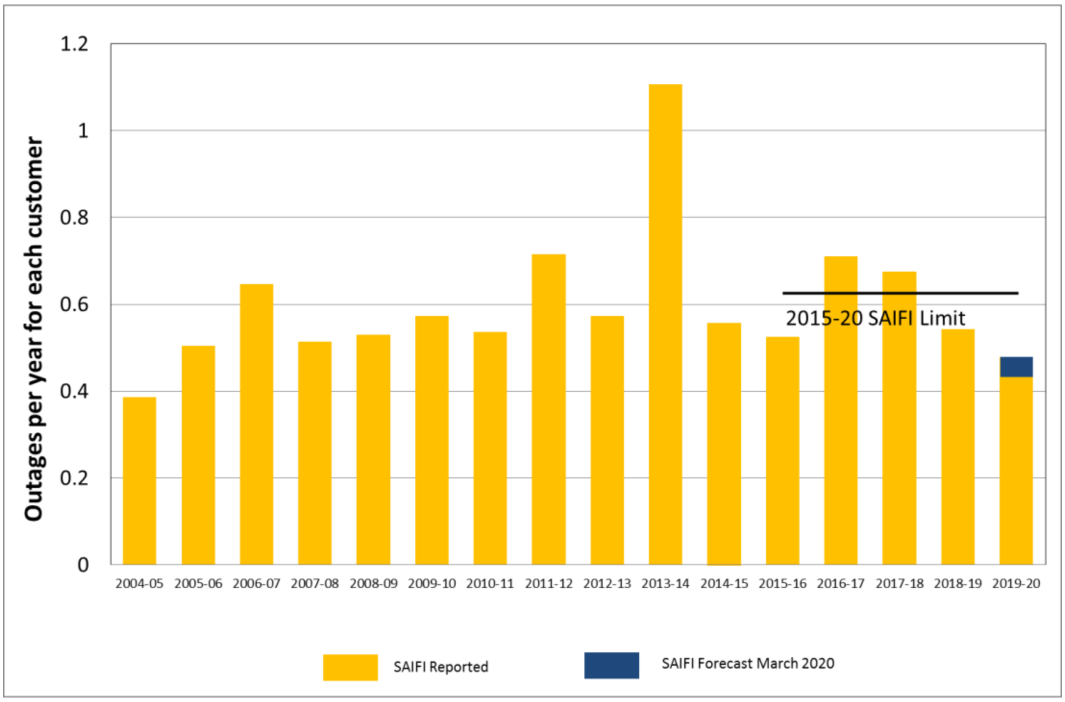


Figure 5-4 WELL SAIFI Performance

WELL's reliability targets align with its asset management network reliability objectives as follows:

- Maintain overall network reliability at historical acceptable levels;
- Deliver the cost-quality trade-offs that customers request; and
- Meet regulatory standards on power quality (discussed in Section 8.1).

5.2.2 Process for Measuring Reliability Performance

This section explains how reliability performance is recorded and validated.

5.2.2.1 Outage Data Collection

The control system WELL uses to record SAIDI and SAIFI information is the PowerOn Fusion (PoF) SCADA network management system (the system). The system is used for the real-time management and monitoring of the high voltage network. Specifically, the system provides information about the status of the network, including customer connection points and devices like circuit breakers and fuses. The system automatically records outage information (including SAIDI and SAIFI details) in a database for all planned and unplanned outages of 11 kV and greater (the high voltage network), including details about the length of the outage and how many customers were impacted.

All of the outage information is then error checked and validated daily by the Network Control Team Leader and an Asset Engineer to ensure it is correct. The reviewed data is recorded in the reliability report sheet.

The process to record and validate network performance information for planned and unplanned outages is shown in Figure 5-5.

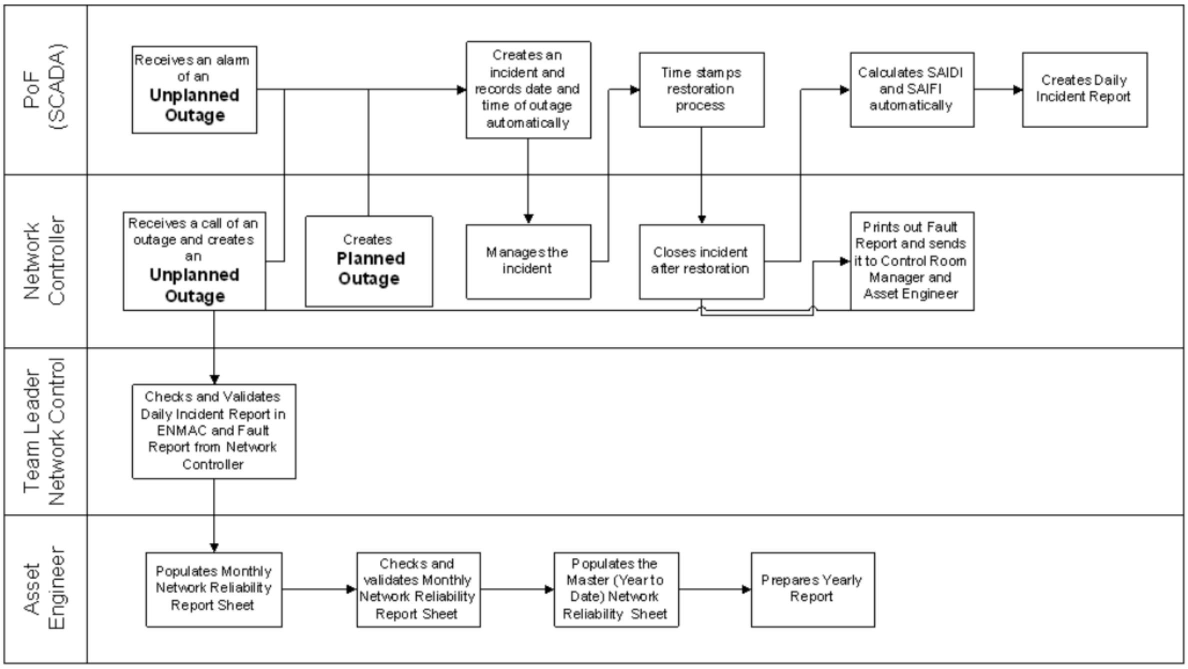


Figure 5-5 WELL Reliability Measurement Process

For unplanned outages, the system identifies there has been a fault, automatically logs the incident and time stamps when it occurred. Any subsequent switching operations are also recorded and time stamped.

For faults on devices that are not directly monitored by the system, the outage is recorded from the time of the first customer phone call relating to the high voltage fault. Subsequent switching operations are manually recorded and time stamped within the system.

5.2.2.2 Data validation and review

After an outage is resolved, an outage report is generated which includes notes from the network controllers on duty. The information is then validated for the following:

- Date outage started and ended;
- Time outage started and ended;
- Duration of outage;
- Number of customers impacted;
- Total customers minutes lost (based on switching operations);
- Total customer number (on network);
- SAIDI for outage;
- SAIFI for outage;
- Fault type; and
- Fault cause.

The data is reviewed for accuracy. Particular attention is given to non-system faults where the information is manually entered by the network controller. Systems faults are automatically generated and rarely have errors. The Network Control Team Leader reviews all faults and approves the daily fault reports as accurate.

The Asset Engineer then compiles the reviewed individual event reports into a monthly network reliability report which is used for monthly reporting of SAIDI and SAIFI indices. The monthly reports are then aggregated into the master database from which WELL's regulatory quality reporting is derived.

5.2.2.3 Planned outages

For planned outages, the proposed switching operations are entered into the system by the Network Controller prior to the event. During the event, the system creates an incident and the Network Controller enters the time the operation occurred. Planned events are validated by the network controllers and the Network Control Team Leader by referring to the specific job documents. The validation process considers whether LV back feeds or portable generation have been used to ensure there was no loss of supply.

5.2.3 Industry Comparison

WELL was one of the most reliable EDBs in New Zealand in 2018/19 as shown in Figure 5-6 and Figure 5-7. The data source is the annual Information Disclosures made by EDBs and made publicly available in

August 2019. The benchmarking analysis shows that WELL's system reliability indices (i.e. SAIDI, SAIFI) are currently performing well against comparable networks in New Zealand (shaded in green).

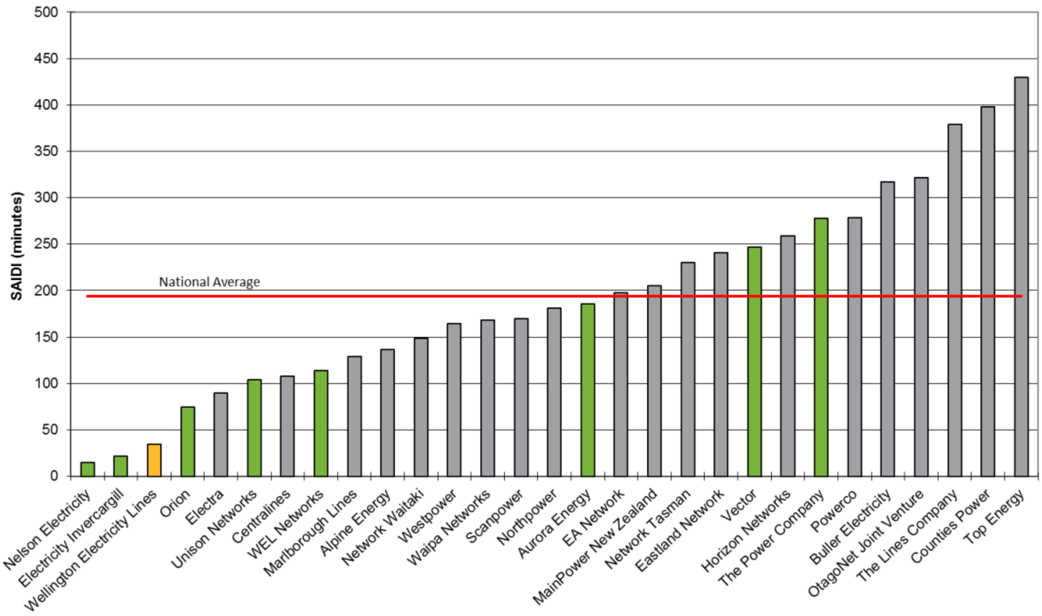


Figure 5-6 National SAIDI by EDB for 2018/19

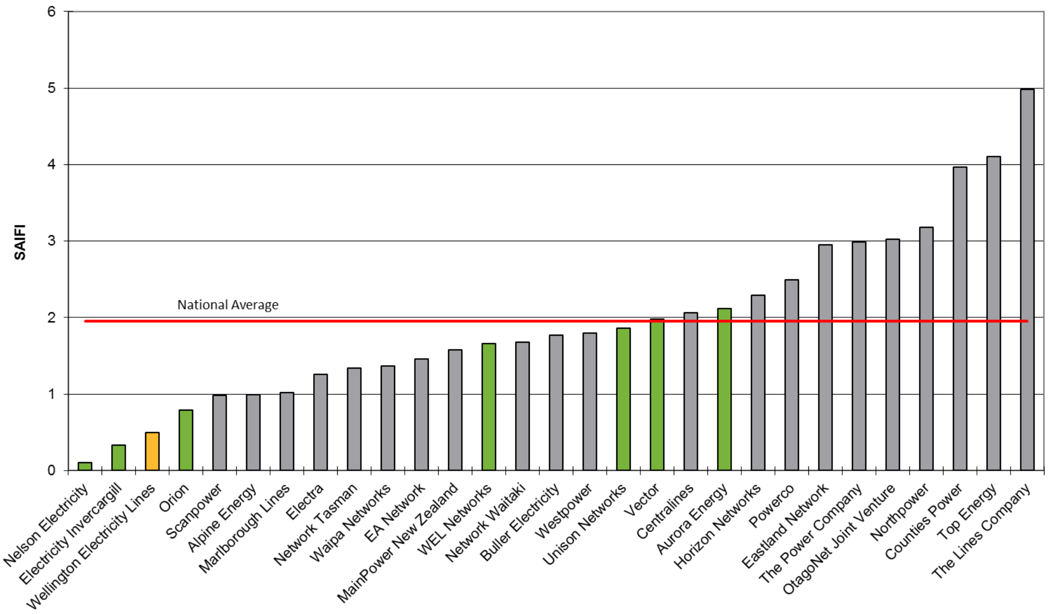


Figure 5-7 National SAIFI by EDB for 2018/19

5.2.4 Reliability Performance in 2019/20

WELL's network performance for the 2019/20 regulatory year was under the annual limit of 40.63 minutes for SAIDI and under the yearly limit of 0.625 for SAIFI.

WELL's SAIDI performance in 2019/20 across a range of fault causes is shown as a waterfall chart in Figure 5-8. The fault causes represented in the chart are:

- Overhead network faults;
- Underground network faults;
- Substation faults;
- Car versus pole faults;
- Other third party faults;
- Planned work;
- Major event days, and
- Other outage types.

Overhead faults have been further separated into those caused by asset failure, and those that were not (non-asset failure outages include those caused by vegetation, lightning, and animals). Major event days are listed as a separate category in order to account for normalisation.

Each of these categories is shown as either being smaller (coloured in green) or larger (coloured in red) than their average contribution during the reference period, with the whiskers on the chart being the standard deviation of the reference period data.

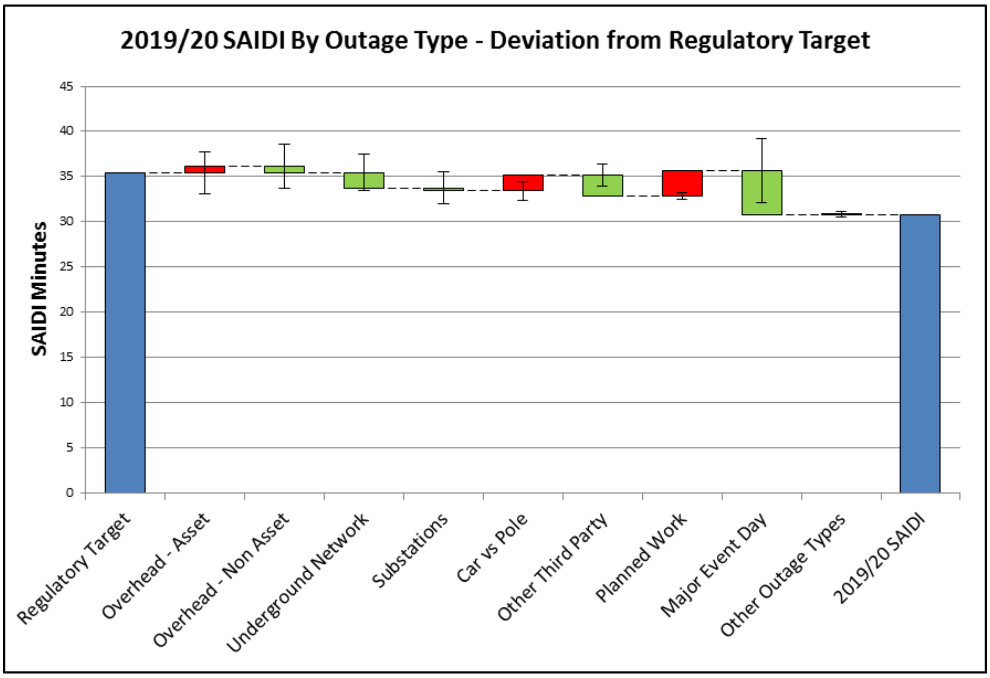


Figure 5-8 Waterfall Chart of 2019/20 SAIDI Performance by Outage Type

The equivalent chart for 2018/19 is shown in Figure 5-9.

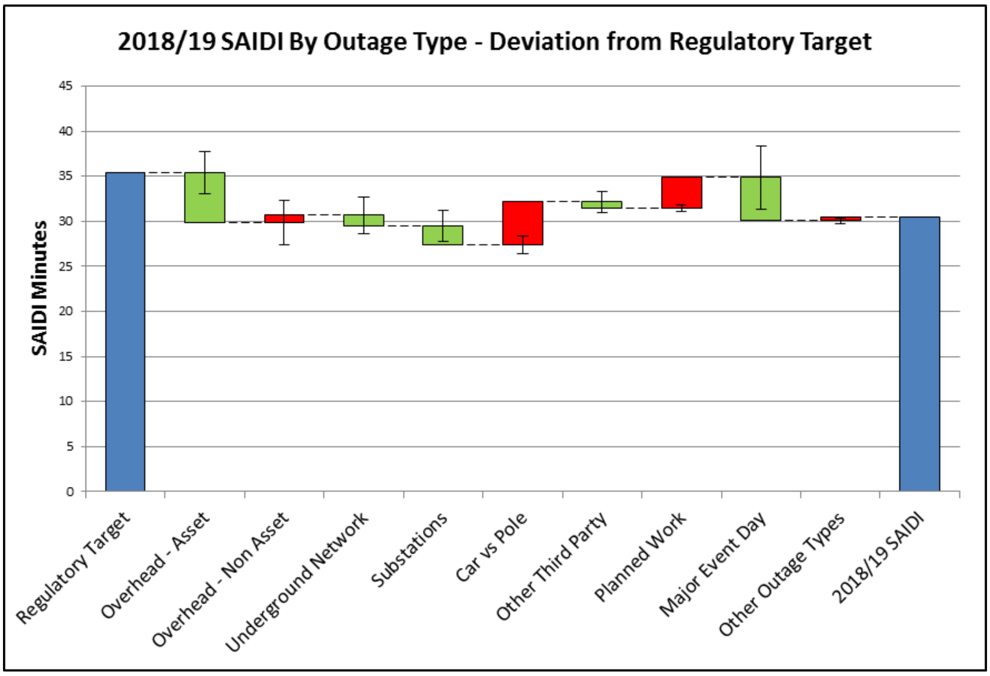


Figure 5-9 Waterfall Chart of 2018/19 SAIDI Performance by Outage Type

Comparing the two years shows that each year's performance is driven by different fault categories and there is no discernible trend in performance.

5.2.5 Reliability Contribution by Network Area

Figures 5-10 and 5-11 show the SAIDI and SAIFI contributions from each network area, representing the availability of electricity supply to the average customer in each region (as opposed to the total number of customers supplied by the network). These charts highlight the difference between the reliability of Wellington city, due to its predominantly underground construction, and the overhead areas supplying the Hutt Valley and Porirua.

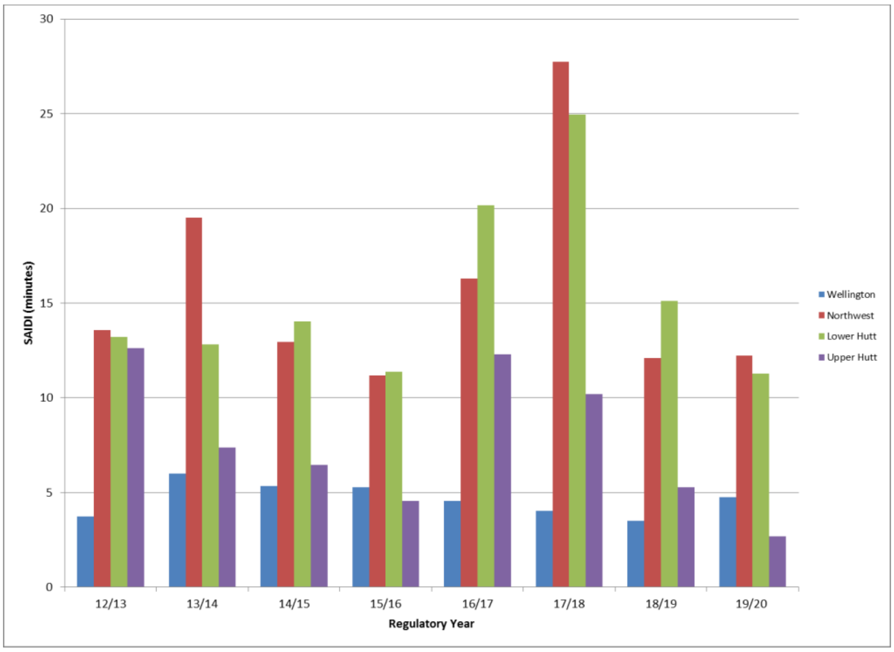


Figure 5-10 SAIDI Contribution by Area

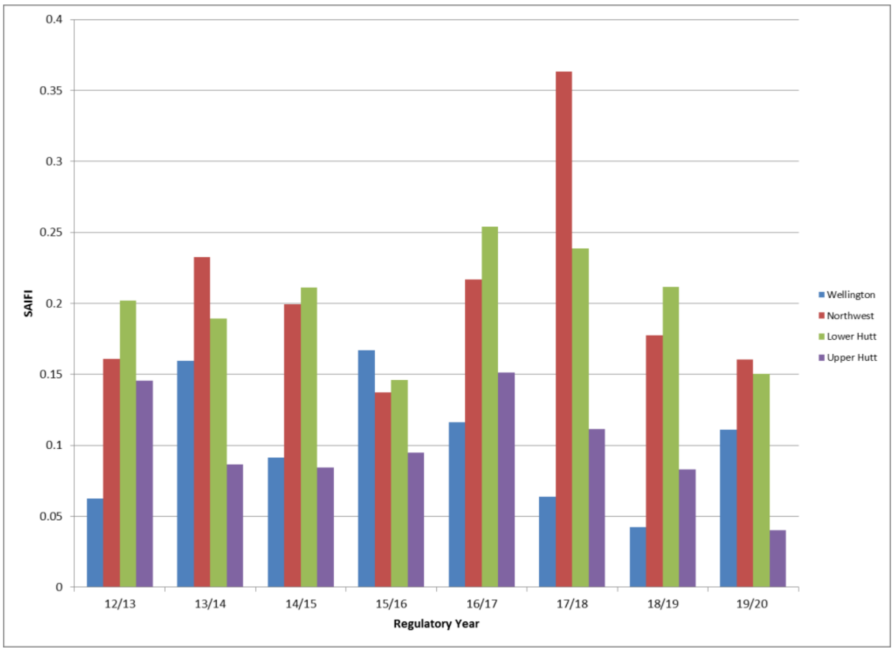


Figure 5-11 SAIFI Contribution by Area

5.3 Asset Efficiency 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. WELL's predominantly urban network results in a higher than average utilisation and load density. The asset performance levels relate to the effectiveness of WELL's fixed distribution assets.

5.3.1 Planning Period Levels

WELL aims to maintain the high level of utilisation of assets at current levels, and in line with other networks that display similar characteristics. WELL has a very high customer density but below average energy density per ICP. Table 5-1 illustrates the 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 intensity kWh/ICP
Industry average[20]	59.4	32.0	5.5	39.8	185.7	12.3	15,903
WELL	50.6	38.8	4.8	114.9	484.9	35.4	13,703
Levels 2020-2030	>50%	>40%	<5%	-	-	-	-

Table 5-1 WELL Asset Efficiency Levels to 2030

WELL is expected to remain at the current levels over the planning period.

[20] Values as per the Pricewaterhouse Coopers (PwC) Electricity Line Business 2019 Information Disclosure Compendium.

5.4 Customer Experience Service Levels

It is important that WELL balances services that customers require with the value they place on these now and into the future. WELL has set the following asset management objectives related to customer service levels:

- Understand our customers' needs;
- Deliver excellent customer service;
- Adjust quality and types of innovative services to match customer needs;
- Reduce unit costs over time; and
- Implement whole-of-life least cost solutions.

WELL uses the insights received from its 'Voice of Customer' (VOC) programme to better understand the critical areas of concern for customers, their perceptions of the service provided and to inform investment plans for the planning period. Examples of VOC inputs are: surveys conducted with customers recently impacted by outages, community engagement events and analysis of the feedback received from customers through WELL's various contact channels.

In 2019, WELL engaged in a number of initiatives aimed at improving customer experience and supporting those groups most in need, some examples being:

- **EnergyMate:** One of the early areas of focus arising out of the Electricity Price Review (EPR) process was on Energy Hardship. WELL was one of the first EDBs to commit to participating in the pilot of 'EnergyMate' - a programme, initiated by the Electricity Retailers' Association of New Zealand (ERANZ), aimed at helping improve the situations of those customers in Energy Hardship.
- **Connections & Self-Service:** WELL upgraded its website platform, using the opportunity to review and improve the quality of information provided to customers. At the same time, a self-service portal for connections requests was established as the first phase of a programme aimed at improving the customer experience for those customers wishing to enquire about and request services from WELL.
- **Community Engagement:** WELL met with the communities most impacted by outages in the Wellington region to engage on the topics of vegetation management (to improve electricity reliability and service), pricing and cost/quality trade-offs and future plans for the network.
- **Wellington City Council Streetlight Maps:** WELL collaborated with Wellington City Council to support development of an outage map for streetlight faults, enabling customers to check whether the council is aware of a fault and to view when it is likely to be resolved.

In 2020, WELL will be delivering four new customer experience improvement programmes:

- **Self-service improvement:** Continued development of the web-based self-service platform to further broaden the number of services able to be requested through the portal and to provide improved monitoring tools for customers to view the progress of their requests.

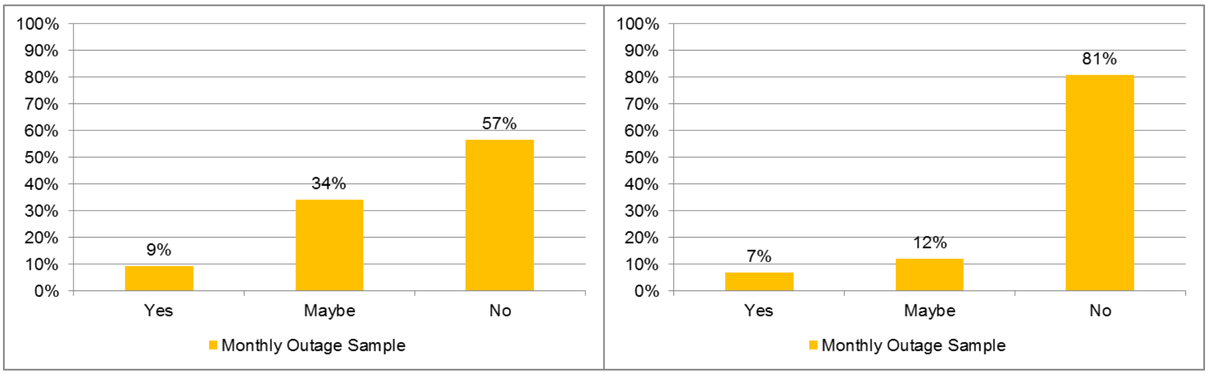
- **Service improvement:** WELL reviews any complaints received from customers and/or their retailers to understand and address the causes of those complaints. In 2020, WELL is taking a more in-depth approach to this work by using detailed analysis of complaints received over the last three years to establish a list of actionable priorities for service level improvement. It is expected that the approach taken and lessons learnt from this year's programme will be rolled into the company's business as usual work processes.

- **Community engagement:** WELL will continue engaging with communities most impacted by outages to align its effort with the 'Worst Performing Feeder' programme.

- **Council streetlight maps:** WELL will be working with at least one other council to support development of this capability.

5.4.1 Customer Engagement

WELL conducts a monthly customer survey to understand customer perceptions across a range of factors and includes questions which seek to understand whether customers perceive that the price-quality trade-off they receive is appropriately balanced. The monthly survey group ("Monthly Outage Sample") consists of customers who have recently experienced an outage, on the basis that they are more engaged on the issue and are better positioned to provide a considered response to queries. The results of that survey are compared in Figure 5-12 for two of the key price-quality trade-off questions.



Q1. Would you be prepared to pay a bit more for your power if it meant fewer power cuts?	*Q3. Would you be prepared to have slightly more power cuts if it meant your electricity bill was a bit lower?*

Figure 5-12 Sample of 2019 Customer Survey Results

For Question 1, the percentage of people willing to pay a bit more for power in return for fewer power cuts remains low, with the majority of customers expressing that they are not prepared to pay more for fewer power cuts. This result is consistent with previous years.

The results for Question 3 suggest that customers are broadly satisfied with their current level of reliability and the price of delivering that service. This view is supported by WELL's position (yellow diamond) in the low SAIDI / low price[21] quadrant of the benchmarking analysis in Figure 5-13.

[21] WELL uses revenue per ICP as a proxy for price given the availability of data this information disclosure.

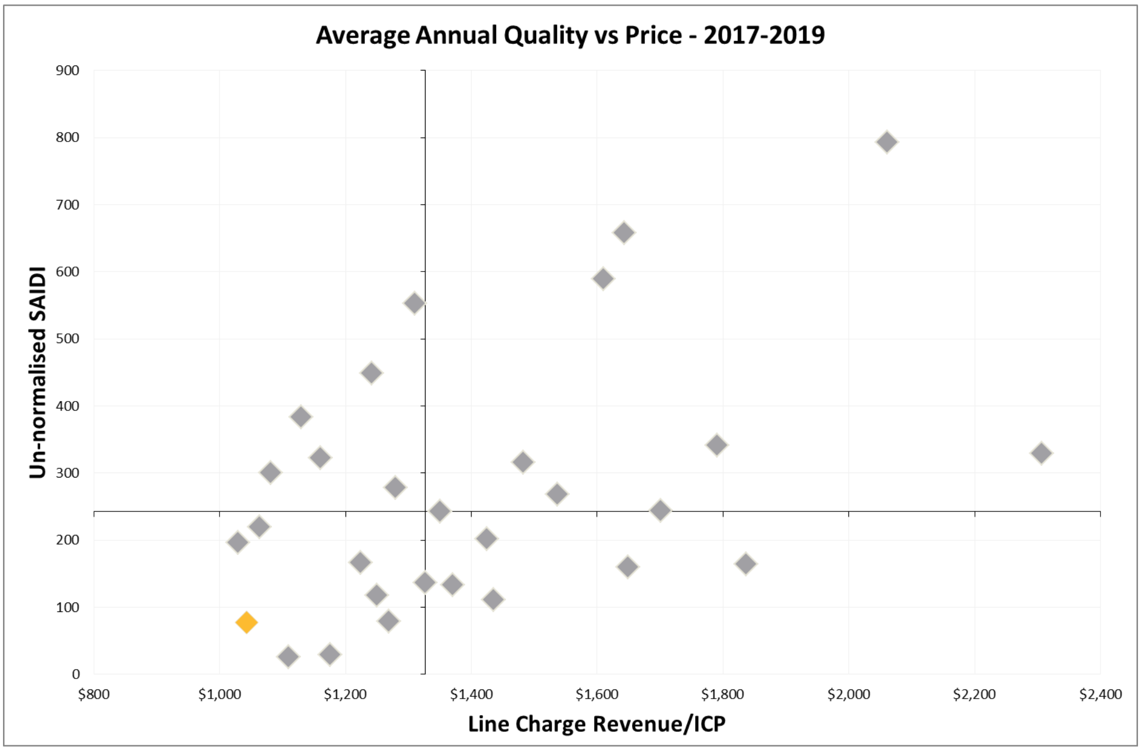


Figure 5-13 Quality – Price Comparison

In the past year WELL has engaged with communities to better understand their experiences and use their opinions to help develop and improve the level of service and ultimately their customer experience. WELL also used this opportunity to provide practical advice on what customers can do to safeguard themselves and their households for unplanned outage situations, and improve their security of supply.

For customers in rural communities, the latter point is particularly important in relation to vegetation management. Specific examples of WELL's engagement include recent visits to the Pauatahanui and Blue Mountains/Whitemans Valley/Mangaroa Valley Residents Associations. WELL has used these experiences to identify gaps in performance and develop plans to improve services. WELL's intention is to continue such engagement using the insights gained to help improve its services for customers.

During 2019, there were two material Transpower outages that reduced the security to WELL customers supplied from Central Park and Gracefield. WELL organised a workshop in December 2019 with Transpower and a cross-section of Wellington business stakeholders to understand the engagement that the community thinks is reasonable for these kinds of situations. Participants were highly engaged over the reduced security situation. They want to be informed about forecast and unplanned N-security situations and use their own discretion as to which events are of sufficient concern to prompt their own electricity outage response plans. As a result, Wellington Electricity and Transpower updated the communication protocol for major GXPs which includes escalation processes and how stakeholders will be informed.

WELL also regularly engages with city councils in the Wellington region with regards to the Tree Regulations and the issuing of trim and cut notices. This is a practice that will be continued as it helps support WELL's initiative to maintain reliability levels for customers.

5.4.2 Power Restoration Service Levels

WELL's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to two different categories of customers: Urban and Rural. These service levels reflect previous feedback from customer and are agreed between WELL and all retailers.

In addition to reliability and appropriate prices, customers increasingly expect good, timely information on their service and its status. Most customers accept occasional power cuts and the ability to keep them informed when these events occur is also important. Ensuring a reliable, effective information flow to customers is therefore a priority for achieving good customer service. To continue providing effective information to customers, WELL sets and tracks performance targets for the Contact Centre, covered in Section 5.4.3.1. WELL is also developing plans for how to ensure that customers impacted by prolonged outages are kept informed with more detailed status updates than would normally be provided for unplanned outages of a shorter duration.

The geographical region by customer category is shown in Figure 5-14.

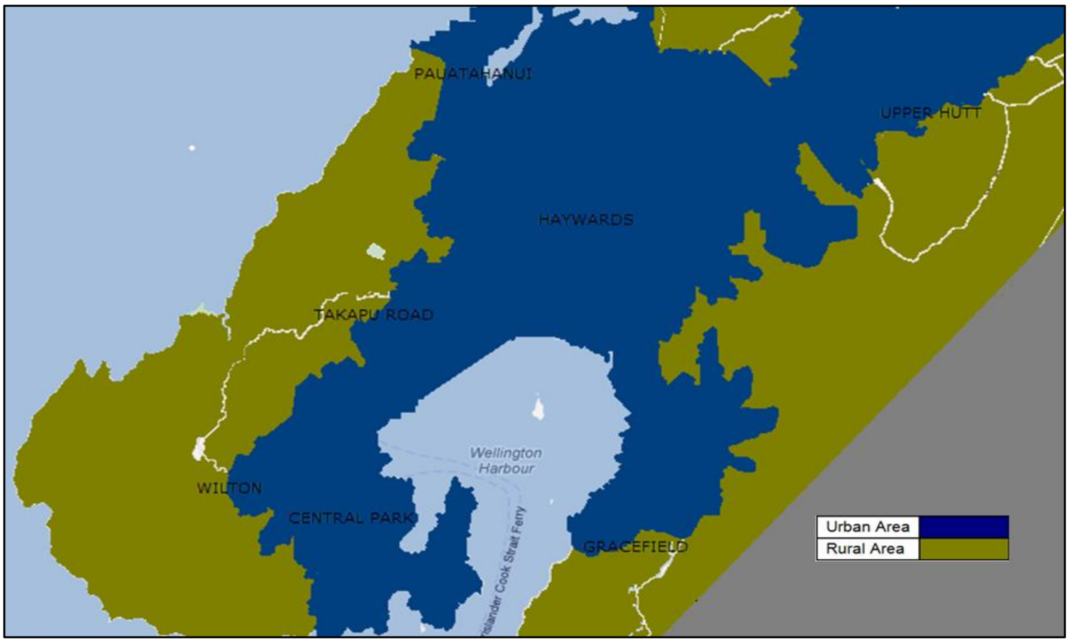


Figure 5-14 Location of Customer Category Areas

5.4.2.1 Planning Period Targets

The targets for the power restoration service levels remain consistent over the planning period 2020-2030, as set out in Table 5-2.

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Table 5-2 Standard Power Restoration Service Level Targets 2020-2030

5.4.3 Contact Centre Service Levels to Customers

WELL measures the service level performance of its Contact Centre through a set of key performance indicators (KPIs). These service levels have been in place since 2013. In 2020, WELL will be undertaking a review of the service level metrics used to assess the Contact Centre's performance.

Feedback from customers, the results of call observations and regular operational reviews are used as inputs into an ongoing performance improvement programme with the Contact Centre. The improvements implemented within the last year have been targeted at:

- Improving the accuracy of outage information published by the Contact Centre via WELL's website outage maps and the OutageCheck app; and
- Making further improvements to agent performance through a review and refresh of knowledge base articles used for agent training and support.

5.4.3.1 Contact Centre Targets

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

1. Overall Service Level (A1) - This is the measure of call quality. Each month between 10 and 20 random call recordings are monitored by the Contact Centre and WELL against 16 quality criteria. The respective scores are compared and discussed. The current target is an overall quality score of 80% or better.

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 WELL website updated, within five minutes of Telnet receiving notice of an outage affecting 10 or more customers. Note that this initial notification, and all subsequent updates, also update the WELL website and OutageCheck smartphone app.

5. Outage Communications (B2): This is a measure of ongoing outage updates. Retailers and the WELL website/outage app 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 WELL website/OutageCheck app will be updated.

7. Outage Communications (B4): This is a measure of ongoing outage updates for more prolonged outages. Retailers and the WELL website/OutageCheck app 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 WELL website/OutageCheck app updated, within five minutes of Telnet receiving notice of outage restoration.

Providing a positive customer experience is an important part of what WELL does and by extension, its service providers. For WELL staff, Customer Service is one of the key company values. WELL will be developing and implementing a suite of Customer Engagement tools to help improve the collective skills across the organisation and thereby constantly seek to improve customer experience.

Table 5-3 sets out the results for the A1 to A3 measures for the 2020 year.

SL	Service Element	Measure	KPI	2019 Actual
A1	Overall service level	Average service level across all categories	>80%	88.58%
A2	Call response	Average wait time across all categories	<20 seconds	1.30 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	<4%	2.88%

Table 5-3 Contact Centre Performance

5.4.3.2 Planning Period Targets

The Contact Centre service level targets are to provide consistent performance over the planning period 2020-2030. These are shown in Table 5-4.

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 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
B5	Restoration Notification	Energy retailers notified and the WELL website updated within the time threshold from the time of restoration	<5 minutes

Table 5-4 Customer Satisfaction Service Level Targets 2020-2030

Section 6

Reliability Performance

6 Reliability Performance

Electricity is an essential service for the community. While large disruptions can occur, and some interruption is expected, customers also reasonably expect to have supply returned without undue delay, as their welfare and the region's economy will quickly suffer if the power stays off for prolonged periods. For this reason, WELL is committed to providing customers with a consistent level of reliable and secure electricity supply under normal conditions. This commitment recognises that customers do accept some level of interruption, rather than pay higher prices to avoid less frequent or lower probability events.

The performance of the network in the 2019/20 year was good, following a positive 2018/19 year result. These two years follow on from a regulatory quality breach in 2016/17 and 2017/18 which is currently under investigation by the Commission. WELL is working positively to answer questions from the Commission and to highlight that the network generally performed better than the reference period, and therefore it is unlikely that there are material asset ageing issues impacting reliability.

This section explains how network reliability is managed. The structure of the section is:

- Reliability performance limits and targets;
- Reliability strategies;
- How WELL forecasts reliability;
- Feeder reliability analysis; and
- Reliability controls.

6.1 Reliability Performance Limits and Targets

The regulatory regime that applies to WELL sets reliability limits for each year. The DPP2 price-quality regime in place from RY16 to RY20 set limits that were one standard deviation above the historical performance during a reference period of 1 April 2004 to 31 March 2014.

The DPP3 price-quality regime, coming into effect on 1 April 2020, has a number of significant changes from DPP2:

- The reference period is the ten years from 1 April 2009 to 31 March 2019;[22]
- Planned and Unplanned indices are to be measured separately;
- Planned indices are no longer halved;
- Unplanned limits are set at 2 standard deviations above the reference period average;
- Unplanned compliance is measured annually, instead of on a two out of three year basis;
- Planned limits are set at 300% of the reference period average;
- Planned compliance is measured once at the end of the regulatory period;

[22] Major events within the reference period are normalised to create a like-for-like comparison.

- Major events are normalised on a rolling 24 hour window, instead of by calendar day; and
- Introduction of an Extreme Outage compliance standard (discussed in Section 6.1.1).

WELL is on a CPP until 31 March 2021. The quality component of this CPP is identical to DPP2, so WELL will continue to be measured against the DPP2 methodology for one additional year, moving onto the DPP3 methodology from 1 April 2021.

The regulatory limits for WELL are presented in Table 6-1. The historical reliability performance against the DPP2 regime is shown in Section 5.2.

Regulatory Year	2015/16-2019/20	2020/21	2021/22-2024/25
Annual Total SAIDI Limit	40.63	40.63	-
Annual Total SAIFI Limit	0.6250	0.6250	-
Annual Unplanned SAIDI Limit	-	-	39.81
Annual Unplanned SAIFI Limit	-	-	0.6135
Period Planned SAIDI Limit	-	-	55.76[23]
Period Planned SAIFI Limit	-	-	0.4429[24]
Extreme Event Customer Minutes Limit	-	-	6 million

Table 6-1 WELL Regulatory Reliability Limits

Figure 6-1 shows the last ten years of actual unplanned SAIDI renormalised using DPP3 methodology, against the DPP3 unplanned SAIDI limit. This supports WELL's confidence that it will be able to meet these limits, and that it is adequately funded to maintain network reliability at current levels.

[23] Pro-rata four year limit out of the five year limit of 69.70 SAIDI minutes.

[24] Pro-rata four year limit out of the five year limit of 0.5536 interruptions.

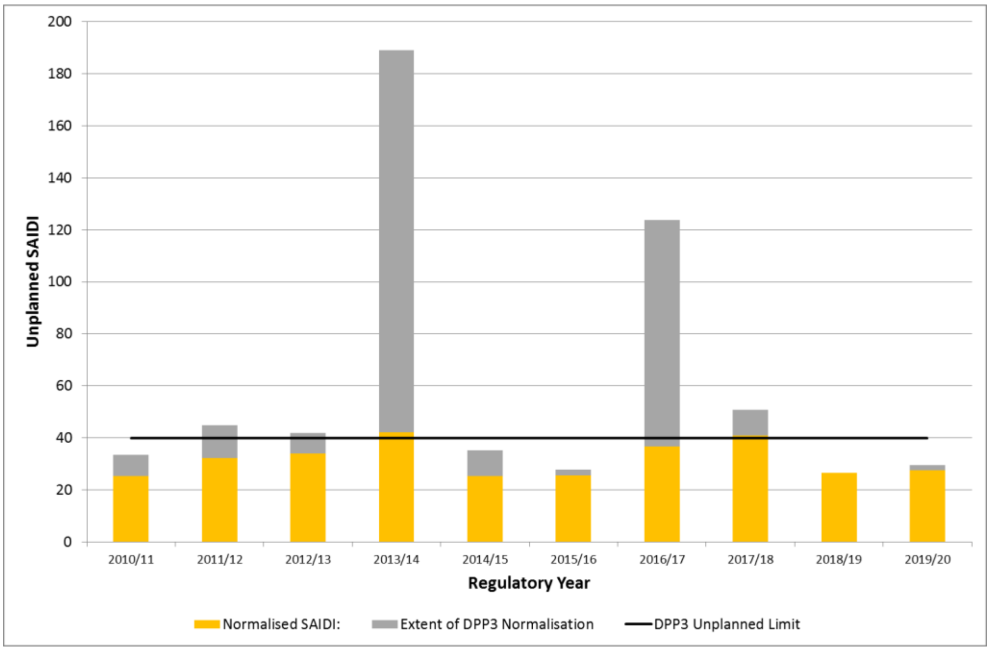


Figure 6-1 DPP3 Normalisation Applied to Historical Performance

WELL's targets for SAIDI and SAIFI are shown in Table 6-2. These targets assume that the SAIDI and SAIFI targets beyond 2025 will be calculated using the same methodology as the 2019 DPP3 determination.

Regulatory Year	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2018/19	2027/28	2028/29
Total SAIDI target	35.44	35.44	-	-	-	-	-	-	-	-
Total SAIFI target	0.547	0.547	-	-	-	-	-	-	-	-
Unplanned SAIDI target	-	-	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20
Unplanned SAIFI target	-	-	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480
Planned SAIDI target[25]	-	-	8.48	8.48	8.48	8.48	8.48	8.48	8.48	8.48
Planned SAIFI target	-	-	0.067	0.067	0.067	0.067	0.067	0.067	0.067	0.067

Table 6-2 Network Reliability Performance Targets

6.1.1 Extreme Event Compliance Standard

DPP3 introduces an Extreme Event compliance standard. The purpose of this standard is to identify events with an extreme impact on customers, that would otherwise not be captured by the other quality measures due to the effect of Major Event Day (MED) normalisation. Wellington Electricity's Extreme Event standard is set at 6,000,000 customer minutes, which equates to 35.9 SAIDI minutes. The standard excludes outages caused by external factors such as storms and third party interference.

[25] Planned Work is not halved under DPP3, so this target is equivalent to 4.24 SAIDI minutes under DPP2.

WELL has reviewed the areas of its network at risk of experiencing an Extreme Event, and these are summarised in Table 6-3. Funding of $250k is earmarked for the 2021 financial year to mitigate the risk created by this new compliance standard.

Extreme Event	Outage Duration to Exceed Standard	Possible Solutions to Reduce Consequence
33kV Cable Fire at Central Park GXP	2 hours	• Cables within the switchroom already have intumescent coatings - completed. • Thermal cameras monitoring the condition of outdoor cables ($50k in 2021) • Expansion of the site to increase redundancy (see Section 11.6.1).
Loss of Wainuiomata Zone Substation	17 hours	• Pre-establish mobile substation and generation connection points.[26] ($25k in 2021) • Contracting distributed energy resources.[27] • Fire suppression in Wainuiomata switchroom. ($175k in 2021) • Accelerate replacement of oil switchgear with vacuum gear.
Loss of Karori Zone Substation	25 hours	• Pre-establish mobile substation and generation connection points. ($25k in 2021) • Contracting distributed energy resources.

Table 6-3 Top Three WELL Extreme Event Risks

6.2 Reliability Strategies

From a reliability management perspective, WELL defines three types of outages; unplanned, planned and High Impact Low Probability (HILP). The strategies relating to these outage types are provided in Table 6-4.

Outage type	Relevant Strategies
Unplanned	Asset Fleet, Network Development
Planned	Planned Outage
HILP	Resilience

Table 6-4 Strategies Relating to Different Types of Outages

6.2.1 Unplanned Outages

Asset Fleet Strategies

Asset fleet strategies focus on the management of a specific asset fleet and are discussed in Section 7. The fleet strategies are a predictive tool used to develop the actions needed to achieve targeted future

[26] The mobile substation is a benefit from the SCPP.

[27] Refer to Section 9 that explains current and future planned new technology trials.

reliability levels. A fleet strategy includes a risk assessment of an asset class which considers population characteristics, and asset health and criticality indicators. The output is a list of asset management actions for the fleet which are needed to achieve expected asset performance and reliability (for example, how often to test the assets, when to replace, when to paint etc.). The fleet strategies drive asset condition and asset reliability - key factors influencing the current and future likelihood of unplanned outages and ultimately the customer service provided.

The asset fleet strategies also manage the consequence of potential outage, directing asset investment to more critical assets, e.g. those that service a larger number of customers.

The fleet strategies include forecasting which is used to estimate future population replacement rates, and are a key input into forecast fleet expenditure. These forecasting methods are described in Section 7.2.

Secondary Asset Fleet Strategy

The secondary asset fleet strategy provides the protection and fault indication requirements to effectively manage network security to limit the consequence of unplanned outages. This strategy is discussed in Section 7.5.9.

Network Development Strategies

Network development strategies and plans ensure that the network remains at the targeted security levels, which helps maintains the integrity of the network when outages occur. These strategies are discussed in Section 8.

6.2.2 HILP Outages

Resilience Strategy

A specific portfolio strategy is the resiliency strategy discussed in Section 11. The resiliency strategy outlines the investment needed to mitigate against HILP events. Following the 2016 Kaikoura earthquake there has been a heightened awareness by stakeholders to the risk of major earthquakes in the region, and this has led to a major investment in this area. Although this is not captured by the quality standards, WELL's improved readiness for a major event is valued by our stakeholders and customers.

6.2.3 Planned Outages

Planned Outage Strategy

The planned outage strategy is a collection of guidelines and initiatives that govern planned outage management. The guidelines and initiatives minimise the impact of planned outages, the risks associated with reconfiguring the network and include the protocols for communicating with customers when a planned outage is required.

6.3 Annual Reliability Reporting

Figure 6-2 shows WELL's reporting structure for reliability performance management and includes the associated regular meetings to support each governance and management level and the key reports provided.

The majority of reports include progress against annual reliability targets. If the reports highlight areas of concern, they will normally also provide recommendations to update reliability controls. These recommendations are escalated to the level required to make a decision if a trade-off is required against another company performance indicator. Governance decisions are formally noted in the Board papers and minutes.

Governance level	Meetings	Supporting reports
Board	Quarterly Board meeting	Director Certified Disclosures (IDR, AMP, CS)
		Reliability Board Papers
		Company Performance and KPI reporting
Executive	Fortnightly Executive Planning meetings	Monthly Reliability Report
		Monthly Customer Survey
		Contractor KPI Dashboard Report
	Weekly Executive update meetings	Ad hoc items escalated from mgnt meetings below
Management	Monthly management meeting	Monthly Business Report
	Fortnightly Reliability Meeting	Fortnight Reliability Report
	Monthly Contractor Meeting	Contractor KPI Dashboard Report
		Help desk metrics (customer complaints)
	Contact centre & stakeholder meetings	Contact centre metrics
		Monthly Customer Survey
Operations & engineering	Asset Failure Reviews, Outage approval process, Project Meetings etc.	Daily reliability report
		Daily reactive maintenance report
		Event Driven Reports (outage, failure etc.)
	Customer Feedback Review	Customer Feedback Register

Figure 6-2 WELL's Reporting Structure

WELL's monthly reporting includes forecasts of the year-end SAIDI and SAIFI result for the current regulatory year, to monitor the overall effectiveness of existing reliability controls.

6.3.1 Forecasting SAIDI by Fault Type

The forecast by SAIDI type is based on the historic monthly distribution of SAIDI due to each cause. This forecast method takes year to date SAIDI by outage cause, and scales it by the proportion of annual SAIDI due to that cause that has historically occurred each month. A waterfall chart is used to display this data, with an example given in Figure 6-3.

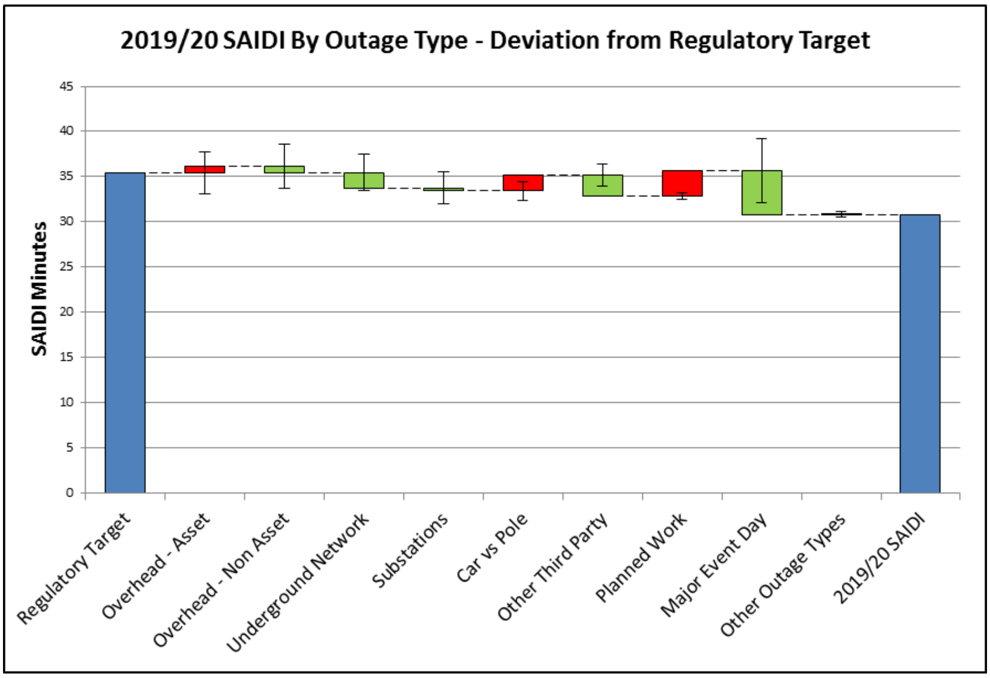


Figure 6-3 Waterfall Chart of 2019/20 SAIDI Performance by Outage Type

This forecast highlights the drivers of the year's performance, and any significant outliers are clearly shown in the context of the standard deviation in the reference period. The chart provides an indication of the effectiveness of controls by outage type, and a trigger to investigate additional controls.

This forecasting method has been actively used since October 2017. The information is included in monthly reporting to the Executive and network performance updates to the Board.

6.4 Annual Feeder Performance Reviews

At the end of a regulatory year, feeders are ranked by a number of reliability performance measures:

- Total SAIDI accrued by the feeder;
- Total SAIFI accrued by the feeder;
- The sum of reliability penalties incurred under price-quality regulation due to the feeder (as a means of combining SAIDI and SAIFI into a single measure); and
- Total number of faults occurring on the feeder.

Feeders that are in the top ten of at least one of the criteria are classed as Worst Performing Feeders. Faults on these feeders are reviewed to determine whether there is a common root cause that could cost effectively be addressed.

Remedial actions identified by this review are fed back into the work programme, where the resulting activities are carried out either under corrective maintenance or as a network project, depending on the scope of the work required.

In an improvement to the previous process, in 2020 each Worst Performing Feeder is to have a documented reliability improvement plan. These plans, which are controlled documents approved by the General Manager Asset Management, contain the following information:

- A description of the feeder (e.g. length, geography, customer type and number);
- A summary of the fault history of the feeder for the last five years, detailing the number of outages by cause type, and the resulting SAIDI and SAIFI;
- More detailed discussion of the primary causes of outages on the feeder, including examination for trends;
- Any findings from outage investigations relevant to the feeder;
- Any relevant links to the fleet portfolio strategies;
- A recommended 10 year Reliability Improvement Programme, comprising actions and timeframes; and
- The forecast expenditure over the next ten years to implement the Reliability Improvement Programme, split into Planned Capex, Corrective Capex, Corrective Opex, and Vegetation Management.

Each reliability improvement plan also includes a visualisation of the location and magnitude of the last three years' outages. An example is provided in Figure 6-4. This graphic highlights the specific areas of the feeder responsible for poor performance, identifies worst served customers, and assists the effective targeting of remedial actions.

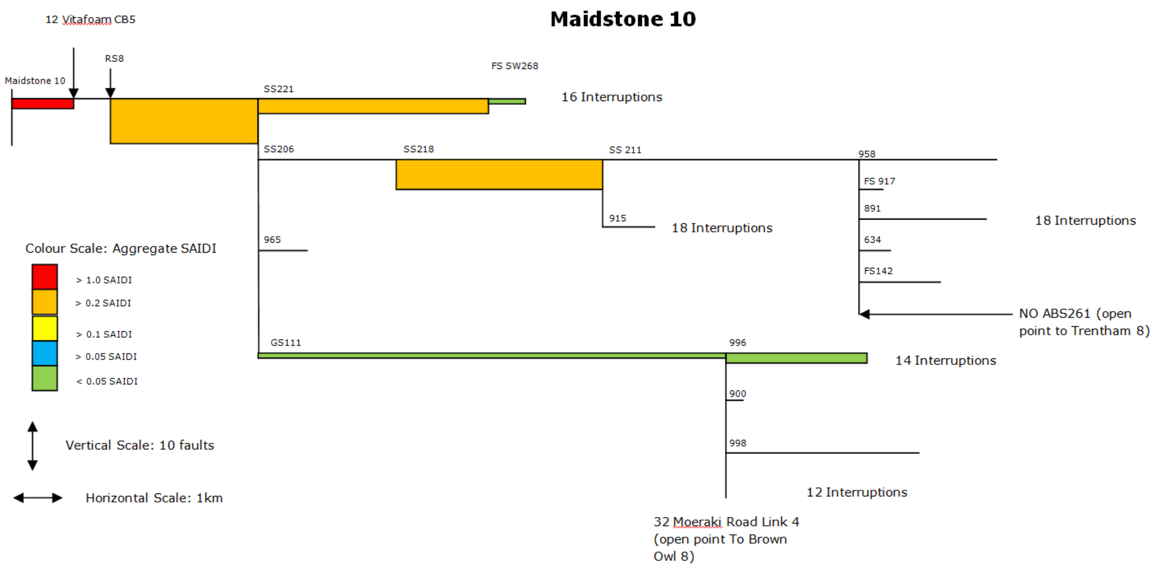


Figure 6-4 Example Feeder Outage Visualisation (Three Years)

Ten of these plans will be written during 2020, along with two plans for potential Worst Performing Feeders. These are feeders that do not have a history of outages, but due to supplying more than 1,000 customers, any future deterioration in their quality would have a significant customer impact. This proactive analysis is to identify potential risks for poor performance, and measures to reduce the impact of future faults.

6.5 Controls by Outage Cause

6.5.1 Planned Outages

Planned outages require balancing customer requirements with the need to safely undertake the maintenance and renewal of the network.

Outage Peer Review

All requests for planned outages are reviewed by the WELL Network Operations team. Any outage that would exceed 0.03 SAIDI minutes is scrutinised to ensure that all cost-effective steps have been taken to minimise customer impact.

Temporary Generation

WELL has used temporary diesel generation to support planned outages since 2018. This has been funded by the DPP2 financial incentive scheme. The reduction in incentive rates for DPP3 means that while temporary generation will continue to be used, this will be at a reduced level from 2021 onwards as the cost of providing generation will exceed the value placed on planned outages by the Commission, unless it is of benefit to a large number of customers. WELL intends to explore modern alternatives to diesel generation as part of its commitment to decarbonisation.

6.5.2 Overhead Equipment

Outage Investigations

All unplanned outages larger than 0.45 SAIDI minutes are investigated by the WELL Asset Engineering team, to understand root causes and recommend improvements. This process has previously identified patterns in component failure, for example specific types of overhead line connectors, resulting in changes to work practices and network standards that will reduce the impact these components have on network reliability in the future.

Lightning

Wellington has traditionally not experienced significant lightning storms. This appears to be changing, with an apparent trend of increasingly severe storms occurring in recent years. In particular, lightning from a storm on 8 December 2019 had a significant impact on WELL's overhead network. WELL is undertaking a detailed review during 2020 of lightning impacts, to determine whether a change in network design standards with increased lightning protection is required due to the changing climate.

Conductor Sampling

WELL is collecting samples of conductors in areas that it is undertaking overhead line rebuilds. These samples are being analysed for fatigue and corrosion, to assist with building a predictive model of conductor condition, and provide a better understanding of future conductor replacement requirements.

6.5.3 Vegetation

Vegetation outages have the potential to significantly impact customers in the overhead sections of the network. WELL has taken significant steps to control the risk posed to the network by trees.

Community Engagement

WELL has engaged with Community Boards in areas impacted by vegetation faults to explain the performance and to highlight ways that local communities can improve the reliability of their power supply by helping to manage trees. One aspect of this approach is the potential for coordinating the outages and traffic management for trees being cut along an entire line. This would reduce the costs that tree owners face in meeting their responsibilities under the regulations.

Risk-based Vegetation Control

WELL and Treescape developed a risk-based approach to managing vegetation outside the regulated zones, which was implemented in 2017. All parts of the network are now assigned a potential reliability consequence, which establishes the level of detail required for tree assessments in that area. Each tree is then assessed for its likelihood of failure, with the level of detail required for this assessment being determined by the potential consequence. The likelihood and consequence are combined to determine the reliability risk the tree poses, and the cost-benefit of cutting it to reduce that risk. Even though the regulations do not give WELL a right to manage vegetation outside of the regulated zones, the risk-based approach has provided WELL with a tool for engaging with tree owners about the potential impact of their trees on the reliability of the power supply.

Covered Conductors

Covered conductors have proven effective at eliminating the reliability impact of wind-borne debris (e.g. branches and bark) in the high vegetation areas where they have been installed. WELL has purchased a quantity of conductor covers, which is available to be installed as areas of need are identified.

6.5.4 Underground Equipment

WELL has commenced a trial of cable testing technology by testing poor performing cables with a variety of diagnostic tools. The purpose of this proactive trial is to gain sufficient understanding of the results produced by these tools and match them to actual cable performance to provide confidence of their suitability as a condition assessment tool to:

- Determine whether a tested cable needs to be pro-actively replaced (either in total or of a targeted section);
- Build a predictive model of cable condition; and
- Forecast future replacements.

It is too early in the programme to start making asset management decisions based on the results. Findings to date relate to the suitability of testing technology and understanding the relationship between test results and future cable performance.

6.5.5 Car versus Pole Incidents

WELL's approach to car versus pole incidents is to reduce the response time for making the incident site safe, which assists emergency services and reduces the impact on customers. WELL is exploring the use of temporary measures such as interrupter cable and temporary pole stands to further reduce the time taken to restore power following an incident.

6.6 External Review

Following the exceedance of reliability limits in 2017/18, WELL's Board requested an external review of WELL's asset management practices. Jacobs was contracted to complete this review by July 2018. The high level scope was to:

- Meet with WELL management and staff to gather information on the reliability performance, outage causes and current practices;
- Review SAIDI data and determine whether there are any particular areas where SAIDI is increasing and the root causes of these;
- Undertake a review of tree trimming practices and benchmark WELL's vegetation opex against industry peers;
- Undertake a review of car versus pole incidents and benchmark against other urban EDBs;
- Undertake a review of equipment failure and consider the adequacy of WELL opex and capex to manage the equipment failure levels over time. Where appropriate, benchmark WELL's capital expenditure on equipment replacement against industry peers with similar network designs;
- Undertake a review of any impact that restricting live line work has had on SAIDI; and
- Report on peer group practices for reliability improvement and any improvement opportunities identified from the above review.

As a result of the review Jacobs made the following conclusions:

- The 2016/17 and 2017/18 reliability exceedances can be explained and are generally not due to a repeating pattern;
- The processes that WELL uses to manage its network reliability are comparable with other similar New Zealand EDBs;
- There is clear evidence that WELL staff are seeking to improve the network's reliability and the associated company processes;
- The peer group Jacobs examined, in comparison to WELL, are predicting (on average) that planned outage levels will continue to rise due to less live-line work;
- WELL's expenditure on vegetation management (per km of overhead line) is above the average spend (per km of overhead line) of its peers;

- WELL's reported equipment failures appear to be relatively constant and do not indicate levels have been increasing;
- There is some evidence that third party vehicle damage has increased in recent times;
- WELL's replacement and reliability capex as a percentage of its annual depreciation was consistent or higher than its peer group; and
- A significant portion of WELL's reported SAIDI/SAIFI is due to faults on its overhead network.

Jacobs' key recommendations were that WELL:

- Continue to refine and expand its Condition Based Risk Management (CBRM) asset management approach to as many asset classes as possible;
- Continue to refine and capture asset fault/defect information in order to identify, as early as possible, any reductions in asset health;
- Continue with its covered aerial conductor trials in order to confirm the benefits of its installation; and
- Consider undertaking a review of the line designs of key/critical overhead lines to ensure that the lines are designed to cope with the weather conditions to which they are subjected.

The recommendations are in progress and are being tracked by the Board.

Section 7

Asset Lifecycle Management

7 Asset Lifecycle Management

This section provides an overview of WELL's assets, and its 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;
- Asset health and criticality analysis;
- Maintenance practices;
- Asset maintenance and renewal programmes; and
- Asset replacement and renewal summary.

7.1 Asset Fleet Summary

A summary of the population for each of the Information Disclosure Requirements (IDR) categories and asset class is shown in Table 7-1.

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Subtransmission	Subtransmission Cables	7.5.1	km	138
	Subtransmission Lines	7.5.3.2	km	57
Zone Substations	Zone Substation Transformers	7.5.2.1	number	52
	Zone Substation Circuit Breakers	7.5.2.2	number	368
	Zone Substation Buildings	7.5.2.3	number	27
Distribution and LV Lines	Distribution and LV Lines	7.5.3.3	km	1,668
	Streetlight Lines	7.5.3.3	km	810
	Distribution and LV Poles	7.5.3.1	number	39,548
Distribution and LV Cables	Distribution and LV Cables	7.5.4	km	2,893
	Streetlight Cables	7.5.4	km	1,113

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Distribution Substations and Transformers	Distribution Transformers	7.5.5.1	number	4,373
	Distribution Substations	7.5.5	number	3,741
Distribution Switchgear	Distribution Circuit Breakers	7.5.6	number	1,292
	Distribution Reclosers	7.5.7.1	number	16
	Distribution Switchgear - Overhead	7.5.7.2	number	2,592
	Distribution Switchgear - Ground Mounted/Ring Main Units	7.5.6	number	2,418
Other Network Assets	Low Voltage Pits, Pillars and Cabinets	7.5.6.1	number	12,406
	Protection Relays	7.5.8.2	number	1,406
	Load Control Plant	7.5.9.4	number	24

Table 7-1 Asset Population Summary

7.2 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 public and worker safety, 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.

WELL takes a risk-based approach to asset lifecycle planning. The preventative maintenance programme is based on each maintenance task having a set cycle based on a known reliability history and is also influenced by any trends in the degradation of asset condition that may occur across a fleet. Corrective maintenance tasks identified during 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, 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 and 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 consumers. 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 insight into the condition and maintenance of each class. This section also provides an overview of maintenance and renewal and refurbishment programmes.

7.3 Asset Health and Criticality Analysis

WELL uses the EEA Asset Health Indicator Guide - 2016. This methodology specifies a number of health indices for each asset class, which are rated on a scale of H5 to H1. Each scale represents a life-cycle phase with varying needs for, or benefits from, replacement. Each of the phases are termed and influenced by end-of-life drivers. The scale is shown in Figure 7-1.

H5	As new condition – no drivers for replacement
H4	Asset serviceable – no drivers for replacement, normal in service deterioration
H3	End of life drivers for replacement present, increasing Asset related risk
H2	End of life drivers for replacement present, high asset related risk
H1	Replacement recommended

Figure 7-1 EEA Asset Health Indicator Scale

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 does not take into account asset criticality or consequence of failure, so WELL developed an Asset Criticality Indicator (ACI)[28] using the same methodology as Asset Health Analysis, incorporating factors such as number of consumers 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. Each number in the matrix gives the quantity of assets, in units or circuit km depending on the asset type, falling into that particular combination of health and criticality. As an example, the health-criticality matrix for power transformers on the WELL network is shown in Figure 7-2 and further discussed in Section 7.5.2.

		Lowest Impact		**Asset Criticality**			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
	1.5				2			
Asset Health	2.0				1			
	2.5				4			
	3.0			7	18		5	1
	4.0			3	7		1	3
Best Health	5.0							

Figure 7-2 Example Health-Criticality Matrix (Power Transformers)

The form of asset risk forecasting used for each fleet varies depending on the type of asset being modelled.

Low volume high value assets such as power transformers are extensively monitored, with a wide range of condition data available from the maintenance programme to support the decisions for managing individual units. The Asset Health-Criticality matrix is used to identify assets at elevated risk, allowing detailed study of specific units to better understand their risk and determine an appropriate response.

For **high volume low value assets** such as poles and distribution transformers, it is not cost-effective to undertake extensive diagnostic testing on an individual basis. These units are replaced when their condition reaches the replacement criteria. The fleets are modelled using survival curves based on historic condition and replacements, to estimate a future replacement profile, without identifying which specific assets are forecast to require replacement in a particular year.

High volume linear assets such as cables and conductors tend to be repaired on failure, with replacement driven through the reliability analysis described in Section 6. The performance of these assets is modelled using fault per km rates.

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[28] The EEA published an Asset Criticality Indicator (ACI) Guide in late 2019, to be used in conjunction with the AHI. WELL's internal ACI will be reviewed in light of this guide in 2020.

Disposable assets such as batteries are replaced at a set frequency, without any asset modelling. Preventative maintenance is used to confirm the asset has not failed prematurely, which in turn is used to ensure the replacement frequency is appropriate.

7.4 Maintenance Practices

7.4.1 Maintenance Standards

WELL currently contracts Northpower as its field services provider to undertake the network maintenance programme under a FSA. Maintenance of all assets is undertaken according to standards that have been developed by WELL.

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 WELL 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 WELL policies and the Electricity (Hazards from Trees) Regulations 2003.

7.4.2 Maintenance Categories

Maintenance is categorised into the following areas:

- **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.
- **Vegetation management.** Planned and reactive vegetation work.
- **Routine and corrective maintenance and inspection.** This comprises:
    - **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.
    - **Corrective maintenance works.** Work undertaken in response to defects raised from the planned inspection and maintenance activities.
    - **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.
- **Asset replacement and renewal.** Reactive repairs and replacements that do not meet the requirements for capitalisation.

The forecast maintenance expenditure for 2020-2030 is summarised by asset class throughout this section.

7.5 Asset Maintenance and Renewal Programmes

This section describes WELL's approach to preventative maintenance and inspections. It also 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 IDR categories (with their associated asset classes) covered are:

- Subtransmission (Cables);
- Zone substations;
- Distribution and LV lines;
- Distribution and LV cables;
- Distribution substations and transformers;
- Distribution switchgear; and
- Other network assets.

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

- A summary of the fleet;
- Any fleet-specific objectives;
- Maintenance activities relevant to the asset class;
- The health-criticality risk of the fleet and the approach adopted to forecast future condition;
- The approach to renewals for the class including life extension activities and innovations; and
- A summary of forecast expenditure for fleet renewals and maintenance.

7.5.1 Subtransmission Cables

Fleet Overview

WELL owns approximately 138 km of subtransmission cables operating at 33 kV. These comprise 50 circuits connecting Transpower GXPs to WELL's zone substations. Approximately 32 km of subtransmission cable is XLPE construction and requires little maintenance. The remainder is of paper-insulated construction, with a significant portion of these cables being relatively old pressurised fluid 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 110 kV but operating at 33 kV. Each individual circuit is modelled using WELL's Asset Health and Criticality systems. The lengths and age profile of this asset class are shown in Table 7-2 and Figure 7-3.

Construction	Design Voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33 kV	30.1%	41.6km
Paper Insulated, Gas Pressurised	33 kV	33.3%	46.0km
Paper Insulated	33 kV	6.7%	9.2km
XLPE Insulated	33 kV	23.5%	32.4km
Paper Insulated, Oil Pressurised	110 kV	6.3%	8.7km
Total			**138km**

Table 7-2 Summary of Subtransmission Cables

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

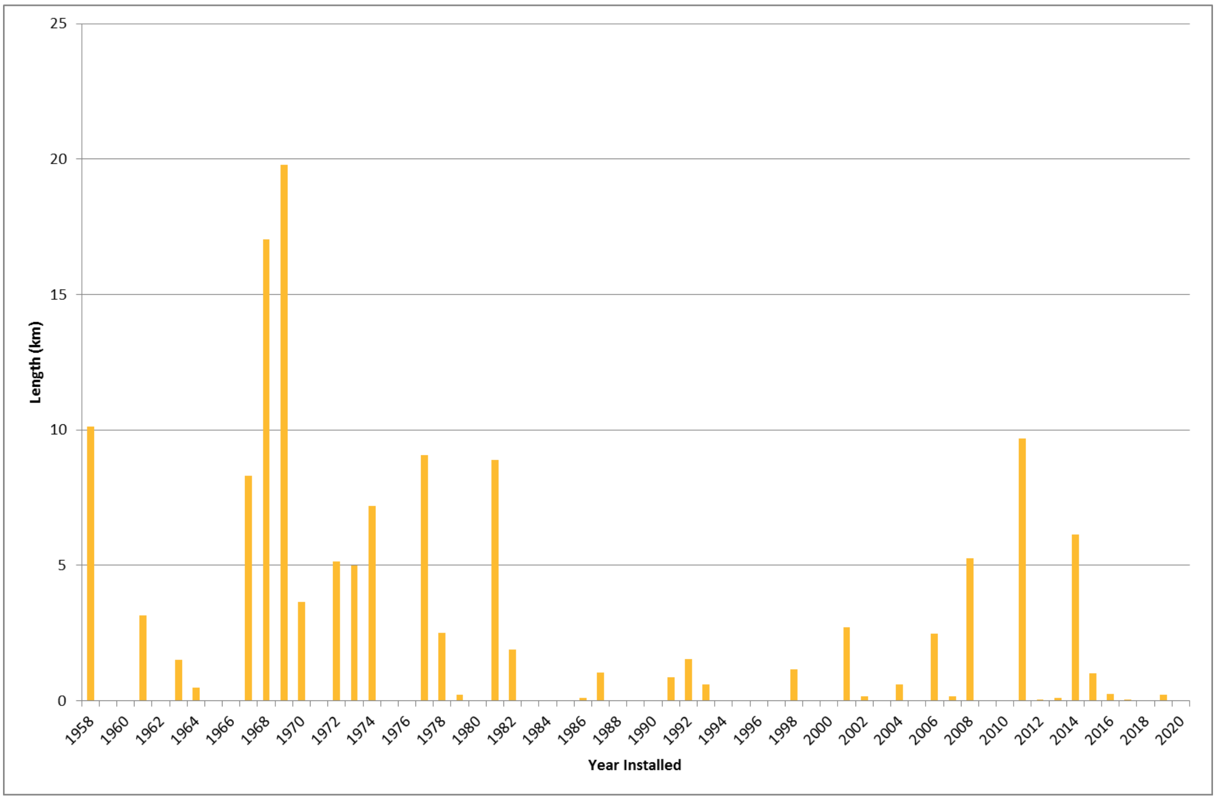


Figure 7-3 Age Profile of Subtransmission Cables

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the subtransmission cable fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around subtransmission cables. Manage the environmental impact of fluid lost from fluid-filled cables.
Customer	Mitigate risk of potential decrease in service or price shock caused by subtransmission cable replacement.
Network Performance	Avoid incurring SAIDI and SAIFI resulting from the tripping of 33kV cables.

Table 7-3 Fleet Specific Objectives for Subtransmission Cable Fleet

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
Cable fluid injection equipment inspection	Inspection and minor maintenance of equipment in substations, kiosks and underground chambers.	6 monthly
Subtransmission route regular patrol	Patrol of cable route; replace missing or damaged cable markers.	Weekly

Table 7-4 Inspection and Routine Maintenance Schedule for Subtransmission Cables

In conjunction with the above routine maintenance schedule, all fluid-filled cables have pressure continuously monitored via the centralised SCADA system, with Executive oversight through a monthly reporting process. This monitoring provides information that identifies cables where fluid is leaking, and allows unexpected pressure changes to be promptly investigated.

Objective condition assessment on cables with fluid pressurisation is limited to leakage rates as a number of cable condition 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 fluid 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 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 Table 7-5.

Strategic Spares	
Medium lengths of cable	Medium lengths of fluid filled 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 to repair standard fluid filled 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 failed transition joints or damaged sections of gas filled cables with non-pressurised XLPE cables where necessary.
Emergency Overhead Line Spares	WELL has designed alternative overhead line routes for all fluid filled subtransmission cables to prepare for the possibility of significant damage post a major earthquake. WELL has procured enough spares to construct 19km of emergency overhead lines. This is part of the approved SCPP programme discussed in detail in Section11.

Table 7-5 Spares for Subtransmission Cables[29]

Cable Condition and Failure Modes

Gas-filled cables

Gas-filled cables are pressurised with nitrogen. They 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. WELL, however, has 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.

Figure 7-4 shows the trend in gas leakage from WELL's gas-filled cables for the 12 months to the end of February 2020.

[29] Section 11 describes additional spare equipment that has been procured under the SCPP application which includes 33kV XLPE cable and joint kits.

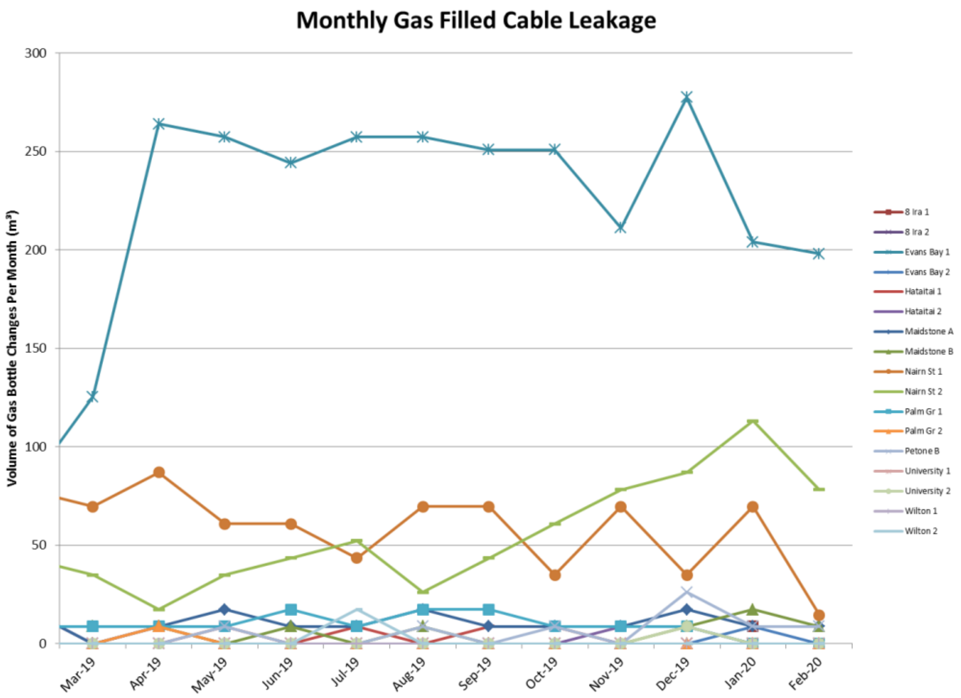


Figure 7-4 Monthly Gas Filled Cable Leakage (as at February 2020)

Fluid-filled Cables

Fluid-filled cables were installed in the WELL network from the mid-1960s until 1991. Some circuits, for example Tawa in 2017 and Johnsonville in 2017, have experienced fluid 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.

Figure 7-5 shows the trend in fluid leakage from WELL's fluid-filled cables for the 12 months to the end of February 2020.

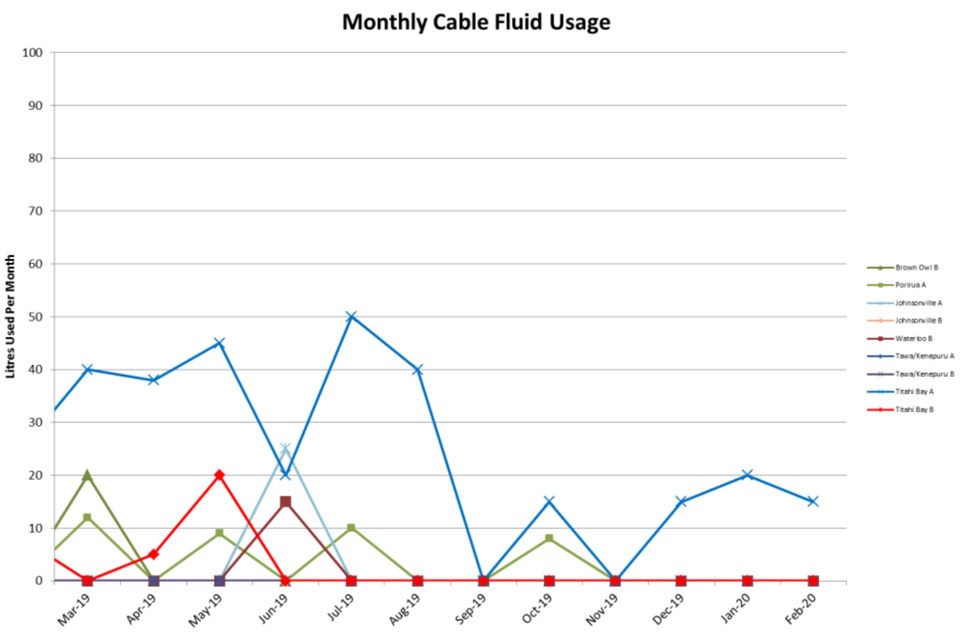


Figure 7-5 Monthly Fluid Filled Cable Leakage (as at February 2020)

Paper and Polymeric Cables

Approximately 30% of WELL's subtransmission cable has solid insulation of either oil-impregnated paper or XLPE. These cables are relatively new compared to the fluid-filled installations and are in good condition, with the exception of University discussed below.

Forecast Future Condition

The future condition of the subtransmission cable fleet is modelled using Asset Health and Criticality Analysis. The analysis categorises cables by risk, triggering further study of the assets with the greatest risk.

The solid insulated cables are performing well. For fluid-filled cables, the only end of life drivers that degrade over time are sheath integrity and fluid leaks. Both of these factors are monitored through the maintenance programme. There appears to be a relationship between age and leakage trends for gas cables, with the health indicator moving from H4 to H3 between 50-60 years of age, and starting to move to H2 beyond 60 years. No such relationship is apparent in the fluid-filled cable fleet, with leaks to date being sporadic rather than due to age-related deterioration.

Aside from the circuits detailed in the Renewal and Refurbishment section below, no further renewal triggered by health is expected to be required during the period covered by this AMP. The potential acceleration of cable replacements for resilience reasons is discussed in Section 11.

<u>Subtransmission Asset Health and Criticality Analysis</u>

The Asset Health and Criticality Analysis results in the health-criticality matrix shown in Figure 7-6, with individual circuit scores and ratings being presented in Table 7-6. 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.

Asset Health	Asset Criticality (Lowest Impact → Highest Impact)							
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0				1			
	1.5				2		2	
	2.0							
	2.5			8	21			2
	3.0							
	4.0			2	8		2	
Best Health	5.0						4	

Figure 7-6 Subtransmission Cable Circuit Health-Criticality Matrix

Subtransmission Circuit	Primary Type	AHI	ACI	Rating
Evans Bay 1	Gas	1.0	2.8	
University 1 & 2	Gas/XLPE	1.8	1.7	
Frederick Street 1 & 2	Gas	2.9	1.3	
Evans Bay 2	Gas	1.8	2.8	

Subtransmission Circuit	Primary Type	AHI	ACI	Rating
Johnsonville A	Fluid	1.8	2.9	
Moore Street 1 & 2	XLPE	4.0	1.8	
Terrace 1 & 2	XLPE	5.0	1.7	
Palm Grove 1 & 2	XLPE	5.0	1.6	
Johnsonville B	Fluid	2.8	2.9	
Maidstone A	Gas	2.8	2.9	
Hataitai 1 & 2	Gas	2.9	2.8	
Ira Street 1 & 2	Fluid	2.9	2.9	
Karori 1 & 2	Gas	2.9	2.9	
Kenepuru A & B	Fluid	2.9	2.9	
Korokoro A & B	Fluid	2.9	2.9	
Maidstone B	Gas	2.9	2.9	
Porirua A & B	Fluid	2.9	2.9	
Tawa A& B	Fluid	2.9	2.9	
Waterloo A & B	Fluid	2.9	2.9	
Waikowhai Street A & B	Gas	2.9	2.9	
Brown Owl A & B	Fluid	2.9	3.0	
Naenae A & B	Fluid	2.9	3.0	
Trentham A & B	Fluid	2.9	3.0	
Waitangirua A & B	Fluid	2.9	3.0	
Ngauranga A & B	XLPE	4.0	2.8	
Gracefield A & B	PILC	4.0	2.9	
Mana	XLPE	4.0	2.9	
Plimmerton	XLPE	4.0	2.9	
Seaview A & B	PILC	4.0	2.9	
Wainuiomata A & B	PILC	4.0	3.0	

Table 7-6 Health Criticality Scores for Subtransmission Cable Circuits

Outcome of Asset Health and Criticality Analysis

The highest priority subtransmission cable circuits, and significant changes since the 2019 AMP, are discussed below.

University

The gas-filled University cables were largely replaced in 2006, however approximately 500 metres of gas cable remains in each circuit. These cables have a high criticality due to University Zone Substation supplying a portion of the Wellington CBD.

Both circuits experienced faults on their XLPE sections during 2015, and laboratory analysis of cable samples revealed issues around premature ageing of the cable insulation due to thermal degradation. Full replacement of both the gas-filled and XLPE cables are expected to be required within the next 10 years, and is currently planned to occur in 2024.

Frederick Street

The gas-filled Frederick Street cables are in reasonable condition; however their location in the Wellington CBD and capacity constraints as identified in Section 8.4.2 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 by 2022 for capacity reasons.

Evans Bay

The Evans Bay subtransmission circuits were installed in 1958 and are the oldest gas cables on the network. After leaking at a consistent rate for five years, Circuit 1 experienced a significant increase in gas leakage in April 2019. To date we have been unable to locate the source of the leak, partly because of the location of the cable route along SH1.

In early 2020, a project was approved to install a 33kV bus at Evans Bay which will be supplied from the two Ira Street cables (which run through the Evans Bay substations) and the healthy Evans Bay Circuit 2. This will create a subtransmission ring with sufficient capacity and security to supply both Evans Bay and Ira Street zone substations. Further detail of this project is provided in Section 8.4.

The longer term plan is to run new cables to Evans Bay within 10-15 years in conjunction with planned transport projects (Let's Get Wellington Moving), expected to allow coordination of new cables as part of the transport corridor work.

In the last six months, the Evans Bay Circuit 2 has developed a small leak. WELL's plan is to locate and repair this leak using a location technique used by UKPN. If the leak is difficult to locate and repair, this may accelerate the installation of the bus and or cable replacement.[30]

Johnsonville

Monitoring during 2015 showed that the oil-filled cables on the Johnsonville A circuit were demonstrating a small but consistent rate of fluid leakage. Location work during 2016 identified this leak as occurring within an area immediately outside the substation at a transition joint and it was repaired in 2017. There have been no further leaks, however the cable remains in the plan for replacement by 2029.

Tawa

A leak developed on the fluid-filled cable on the Tawa A circuit in 2017. This leak was identified as occurring within a stop joint in Morgan Place. The joint was excavated in November 2017 and repairs undertaken. The performance of this joint and cable will continue to be monitored. To date, there has been no further leaking.

Titahi Bay

In 2018 it was identified that a fluid-filled cable on the Titahi Bay circuit, operated at 11kV, was demonstrating fluid leakage. The leak was found to have occurred on the pipe work of the hydraulic system, and was repaired in January 2019. Levels are now back to normal and the cable pressure will continue to be monitored.

<u>Renewal and Refurbishment</u>

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

[30] A contingency plan has been developed to mitigate against various possible outage scenarios.

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.

Significant projects for the renewal of subtransmission cables over the next 12 months are listed in Table 7-7.

Project	Description
Trentham Cable Bushings	The porcelain bushings at the Trentham end of the fluid-filled Haywards-Trentham cables are to be replaced due to poor resistance readings.

Table 7-7 Subtransmission Cable Projects for 2020/21

Expenditure Summary for Subtransmission Cables

Table 7-8 details the expected expenditure on subtransmission cables by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Cable Replacement	412	-	-	500	3,000	-	-	2,000	2,000	-
Capital Expenditure Total	**412**	**-**	**-**	**500**	**3,000**	**-**	**-**	**2,000**	**2,000**	**-**
Preventative Maintenance	85	85	85	85	85	85	85	85	85	85
Corrective Maintenance	200	200	200	150	150	150	150	150	150	150
Asset Renewal and Replacement Opex	312	312	312	312	312	312	312	312	312	312
Operational Expenditure Total	**597**	**597**	**597**	**547**	**547**	**547**	**547**	**547**	**547**	**547**

Table 7-8 Expenditure on Subtransmission Cables
($K in constant prices)

7.5.2 Zone Substations

7.5.2.1 Zone Substation Transformers and Tap Changers

Fleet Overview

WELL has 52 33/11 kV power transformers in service on the network and one spare unit. WELL's power transformer fleet is mature, with the youngest transformers being the pair at University Zone Substation (33 years old). Even so, most power transformers are in very good condition due to their being mostly indoors and loaded to less than 50% of their nameplate rating. The age profile for zone substation transformers is shown in Figure 7-7.

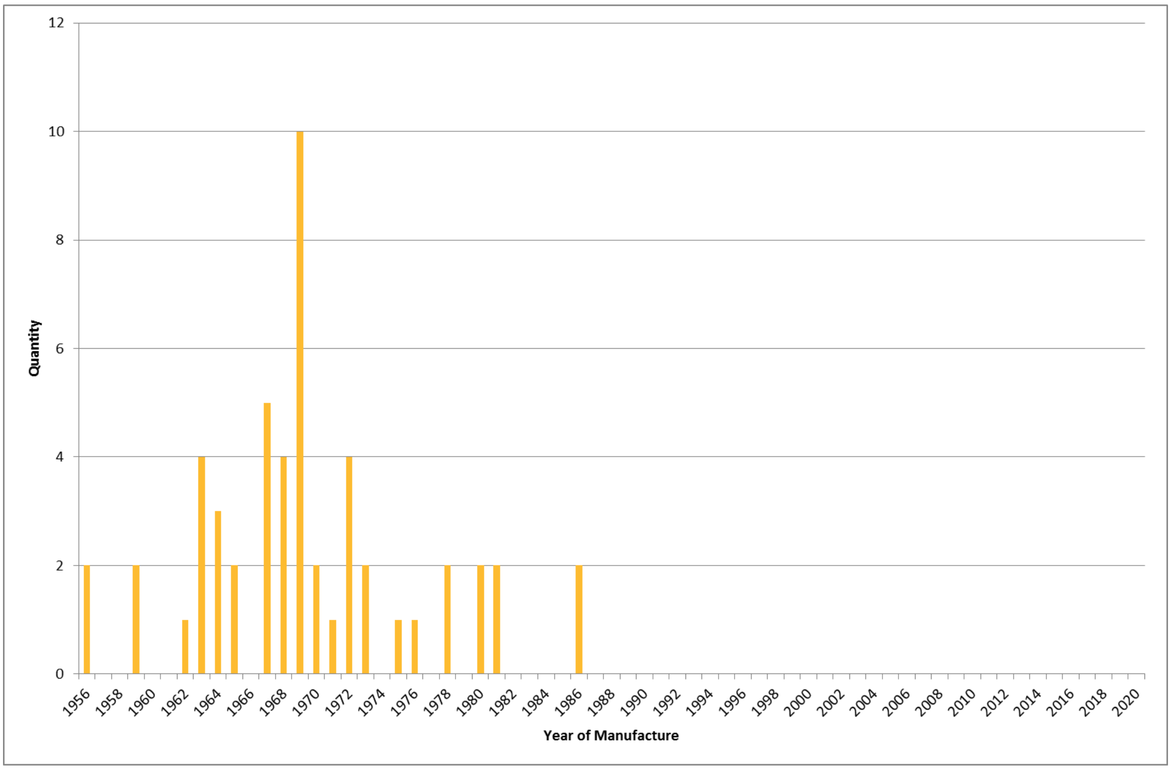


Figure 7-7 Age Profile of Zone Substation Transformers

The mean age of the transformer fleet is 50 years.

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the power transformer fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around power transformers. No public safety risk due to power transformers.
Customer	Mitigate risk of potential decrease in service or price shock caused by unforecasted power transformer replacement.
Network Performance	Avoid incurring SAIDI and SAIFI resulting from unavailability of power transformers.

Table 7-9 Fleet Specific Objectives for Power Transformer Fleet

Maintenance Activities

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

Activity	Description	Frequency
Transformer main tank oil test	Dissolved gas analysis (DGA) testing of transformer main tank oil.	Annually
Transformer tap changer oil test	Dissolved gas analysis (DGA) testing of transformer tap changer oil.	2 yearly
Transformer oil furan test	Furan analysis of transformer main tank oil.	2 yearly
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[31].	4 yearly

Table 7-10 Inspection and Routine Maintenance Schedule for Zone Substation Transformers

Strategic Spares

WELL holds critical spares for the power transformers and tap changers as detailed in Table 7-11.

Strategic Spares	
Tap changer fittings	WELL 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	One spare power transformer is located at Petone Zone Substation. This unit was refurbished in 2018. Should additional spare transformers be required, one will be taken from any of a number of substations that are lightly loaded with sufficient distribution network back-feed options. These include Gracefield and Trentham.
Mobile Substations	As part of its earthquake readiness programme, WELL is currently designing and building two mobile substations. Further information on this is provided in Section 11.

Table 7-11 Spares Held for Zone Substation Transformers

Transformer Condition

All zone substation transformers are operated within their ratings, are regularly tested, and have routine 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,

[31] The frequency of time-based maintenance on tap changers is influenced by the results of the tap changer oil DGA results.

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.

The deterioration of barrier boards on Fuller tap changers has started to manifest on some of the older units in service. This leads to oil migration between tap changer and the main tank. The levels of migration are being monitored via ongoing oil sampling and DGA analysis.

Oil analysis provides 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 is taken to confirm the accuracy of the furan analysis.

In 2016, the tap changer of Frederick Street transformer T1 malfunctioned after tap changer maintenance causing the buchholz relay to trip. This was initially thought to have been caused by a broken mercury switch. A second fault later revealed this was caused by a loosened bolt in the diverter arm resulting in misalignment between the diverter arm and tap contacts. A new diverter arm was provided by the manufacturer and the transformer was put back in service. Diverter arms and bolts and contacts are now checked in addition to the normal tap changer maintenance. In 2017 the tap changer maintenance approach was reviewed and this has now been updated into the new transformer maintenance standard.

The future condition of the power transformer fleet is modelled using Asset Health and Criticality Analysis. The analysis categorises transformers by risk, triggering further study of the assets with the greatest risk.

<u>Transformer Asset Health and Criticality Analysis</u>

The Asset Health and Criticality Analysis results are shown in the health-criticality matrix in Figure 7-8, with individual transformer scores and ratings being presented in Table 7-12.

		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							
	1.5				2			
	2.0				1			
	2.5				4			
	3.0			7	18		5	1
	4.0			3	7		1	3
Best Health	5.0							

Figure 7-8 Power Transformer Health-Criticality Matrix

Transformer	Substation	AHI	ACI	Rating
Evans Bay T1	Evans Bay	1.7	2.8	
Evans Bay T2	Evans Bay	1.9	2.8	
Frederick Street T1	Frederick Street	3.0	1.3	
Mana	Mana-Plimmerton	2.0	2.9	
Frederick Street T2	Frederick Street	4.0	1.3	
Terrace T1 & T2	Terrace	4.0	1.3	
Palm Grove T1 & T2	Palm Grove	3.0	1.6	
University T1 & T2	University	3.0	1.7	
Moore Street T2	Moore Street	4.0	1.8	
Moore Street T1	Moore Street	3.0	1.8	
Tawa A & B	Tawa	2.9	2.9	
Waikowhai Street T1 & T2	Waikowhai Street	2.9	2.9	
Hataitai T1 & T2	Hataitai	3.0	2.8	
Ngauranga A & B	Ngauranga	3.0	2.8	
Gracefield A & B	Gracefield	3.0	2.9	
Johnsonville A & B	Johnsonville	3.0	2.9	
Karori T1 & T2	Karori	3.0	2.9	
Kenepuru B	Kenepuru	3.0	2.9	
Korokoro A & B	Korokoro	3.0	2.9	
Plimmerton	Mana-Plimmerton	3.0	2.9	
Porirua A & B	Porirua	3.0	2.9	
Seaview A & B	Seaview	3.0	2.9	
Brown Owl A & B	Brown Owl	3.0	3.0	
Naenae T2	Naenae	3.0	3.0	
Trentham A & B	Trentham	3.0	3.0	
Wainuiomata A	Wainuiomata	3.0	3.0	
Waitangirua B	Waitangirua	3.0	3.0	
Ira Street T1 & T2	Ira Street	4.0	2.9	
Kenepuru A	Kenepuru	4.0	2.9	
Maidstone A & B	Maidstone	4.0	2.9	
Waterloo A & B	Waterloo	4.0	2.9	
Naenae T1	Naenae	4.0	3.0	
Wainuiomata B	Wainuiomata	4.0	3.0	
Waitangirua A	Waitangirua	4.0	3.0	

Table 7-12 Health Criticality Scores for Power Transformers

Outcome of Asset Health and Criticality Analysis

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.

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. To date corrective works have been possible and the transformers returned to service.

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. The replacement of these transformers is underway for completion by the end of 2022.

Mana

The Mana transformer is a South Wales unit that was manufactured in 1963 and has exhibited a low estimated DP value based on Furan Analysis of 450. The DGAs on this unit show no concerning signs in terms of combustible gases, carbon monoxide or carbon dioxide, however acidic content has been on a steady increase over the past years. Online monitoring has been fitted to the transformer to provide a more detailed estimate of end of life, and this is indicating that replacement is not required within the horizon of this AMP.

Palm Grove

The Palm Grove transformers are in good condition, but have high criticality due to the peak loading and number of consumers 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 8 indicates that the most cost effective option to manage the transformer health in the short term is to deload the transformers on the 11 kV system during the three days a year that the load exceeds the transformer rating, while planning for replacement with larger units by 2025. Section 8 also makes allowance for ring reinforcement from 2025 onwards which will provide a greater ability to shift load between zone substations.

Ngauranga

Ngauranga has the oldest power transformers installed in WELL'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 would be required towards the end of the planning period, however as identified in Section 8.5, replacement of the transformers is planned for 2025 due to capacity constraints.

Frederick Street

Frederick Street has a high criticality index due to its location in Wellington CBD and the number of consumers 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 has continued. Since then moisture has remained at steady levels, but ethylene has started to steadily ramp up again. The ethylene levels will continue to be monitored to determine the best course of action.

Frederick Street T1 is in a higher risk category than T2 due to having a lower estimated degree of polymerisation. This score indicates an estimated remaining service life for the paper insulation of approximately 30 years, so the unit is not expected to require replacement within the horizon of this plan. The DP will continue to be monitored through the routine DGA testing.

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 2017 by a Reinhausen technician who also replaced worn switching star contact rollers.

University 1

The University transformers are only 33 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.

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 Evans Bay[32] zone substation; and
- Ongoing transformer refurbishment costs.

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 will be considered if supported by a business case. For power transformers in the WELL network the testing and inspection programme will aid in getting the best life from the transformer and also ensure optimal timing for unit replacement.

Significant projects for the renewal of power transformers over the next 12 months are listed in Table 7-13.

Project	Description
Evans Bay	Undertake detailed design for the transformer replacement, including design for seismic strengthening of the transformer rooms.

Table 7-13 Power Transformer Projects for 2020/21

Expenditure Summary for Power Transformers

Table 7-14 details the expected expenditure on power transformers by regulatory year.

[32] There are two transformers replaced at Evans Bay substation for asset health reasons. There are also two transformers to be replaced at each of Ngauranga and Palm Grove substations for capacity reasons (refer to Section 8).

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Evans Bay Transformer Replacements	100	1,000	2,200	-	-	-	-	-	-	-
Capital Expenditure Total	**100**	**1,000**	**2,200**	-	-	-	-	-	-	-
Preventative Maintenance	165	165	165	165	165	165	165	165	165	165
Corrective Maintenance	60	60	60	60	60	60	60	60	60	60
Operational Expenditure Total	**225**	**225**	**225**	**225**	**225**	**225**	**225**	**225**	**225**	**225**

Table 7-14 Expenditure on Power Transformers ($K in constant prices)

7.5.2.2 Zone Substation Switchboards and Circuit Breakers

Fleet Overview

11 kV circuit breakers are used in zone substations to control the power injected in to the 11 kV distribution network. There are 368 circuit breakers located at zone substations on the WELL network. The most common single type is the Reyrolle Pacific type LMT circuit breaker. An age profile of these circuit breakers is shown in Figure 7-9.

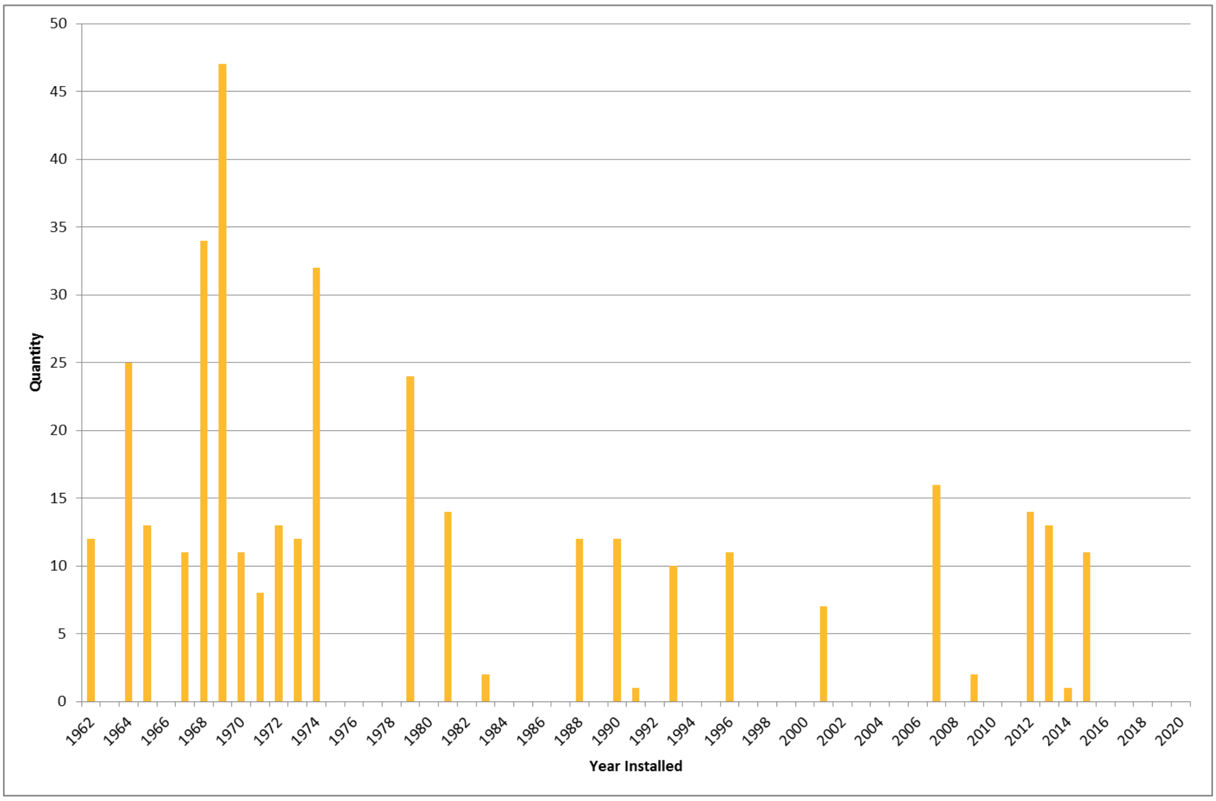


Figure 7-9 Age Profile for Zone Substation Circuit Breakers

The average age of zone substation circuit breakers in the Wellington Network is approximately 40 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 or SF_6 interrupters. The majority of circuit breakers are still oil-filled and require relatively higher maintenance regimes.

The use of transformer feeders avoids the need for 33 kV circuit breakers at zone substations. However, there are two 33 kV Nissin KOR oil circuit breakers at Ngauranga which have been in service at this site for approximately 27 years. Originally manufactured in the 1960s, installation was in 1993 when the substation was constructed. There are plans for the decommissioning and removal of these breakers once the communications systems from Takapu Road have been upgraded. Until then, a spare unit has been obtained from Transpower.

Category	Quantity
33 kV Circuit Breakers	2
11 kV Circuit Breakers	366

Table 7-15 Summary of Zone Substation Circuit Breakers

Manufacturer	Breaker Type	Quantity
Nissin	Oil (33 kV)	2
Reyrolle (RPS)	Oil	275
	Vacuum	75
Siemens	SF_6	16
Total		**368**

Table 7-16 Summary of Zone Substation Circuit Breakers by Manufacturer

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the zone substation circuit breaker fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around circuit breakers.

Table 7-17 Fleet Specific Objectives for Zone Substation Circuit Breaker Fleet

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 33 kV 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 11 kV Circuit Breaker	Visual inspection of equipment and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
33 kV 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
11 kV 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
11 kV 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
11 kV 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
11 kV 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

Table 7-18 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

Strategic Spares

Given the high number of circuit breakers in service on the WELL network, it is important to keep adequate quantities of spares to enable fast repair of defects. The largest quantity of circuit breakers on the network is the Reyrolle type LMT, which is used predominantly at zone substations, and WELL 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 Table 7-19.

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, 400 A current transformers for Reyrolle LMT are held, as this type of equipment has a known issue with partial discharge.
Mobile switchboard	As part of WELL's earthquake readiness expenditure via the SCPP, a containerised 11kV mobile switchboard is being designed and built. This is further discussed in Section 11.

Table 7-19 Spare Parts Held for Circuit Breakers

Switchgear Condition and Failure Modes

The switchgear installed on the WELL network is generally in very good condition. The equipment is installed indoors, has not been exposed to extreme operating conditions, and has been well maintained.

Examples of switchgear in poorer 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 are easily identified and remedied under corrective maintenance programmes.

The future condition of the zone substation circuit breaker fleet is modelled using Asset Health and Criticality Analysis of switchboards. The analysis categorises switchboards by risk, triggering further study of the assets with the greatest risk.

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.

Reyrolle Type C

Reyrolle Type C circuit breakers were installed between 1938 and the late 1960s, and have been the target of a replacement programme. The final remaining units in service at Gracefield zone substation were replaced during 2019, thereby completing this programme.

Reyrolle LMT - Partial Discharge (PD)

Reyrolle LMT circuit breakers were installed on the network from late 1960s onwards and there are over 600 units in service on the WELL network.

In 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 industry 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.

Circuit Breaker Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis results are shown in the health-criticality matrix in Figure 7-10, with individual switchboard scores and ratings being presented in Table 7-20.

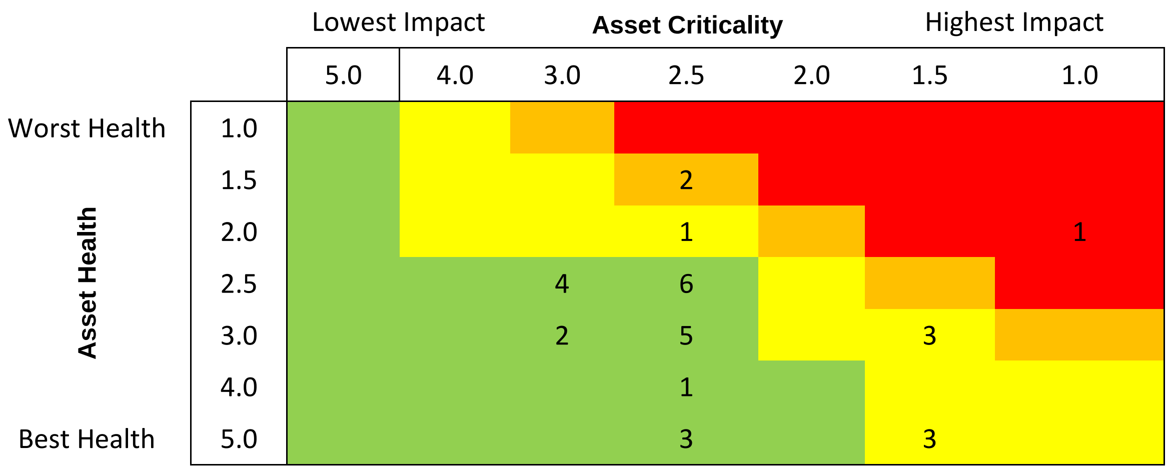


Figure 7-10 Zone Substation Switchboard Health-Criticality Matrix

11 kV Switchboard	Model	AHI	ACI	Rating
Frederick Street	LM23T	2.0	1.3	
Mana	LM23T	1.9	2.9	
Johnsonville	LM23T	1.9	2.9	
Hataitai	LM23T	2.0	2.8	
University	LMT	3.0	1.7	
Moore Street	LM23T	3.0	1.8	
Nairn Street	LMT	3.0	1.8	
Palm Grove	LMVP	5.0	1.6	
Kaiwharawhara	LMVP	5.0	1.8	
Terrace	NX-PLUS	5.0	1.8	
Kenepuru	LM23T	2.9	2.9	
Korokoro	LM23T	2.9	2.9	
Maidstone	LM23T	2.9	2.9	
Plimmerton	LM23T	2.9	2.9	
Porirua	LM23T	2.9	2.9	
Waterloo	LMT	2.9	2.9	
Brown Owl	LM23T	2.9	3.0	
Naenae	LM23T	2.9	3.0	
Trentham	LM23T	2.9	3.0	

11 kV Switchboard	Model	AHI	ACI	Rating
Waitangirua	LM23T	2.9	3.0	
Ngauranga	LMT	3.0	2.8	
Ira Street	LM23T	3.0	2.9	
Petone	LM23T	3.0	2.9	
Seaview	LM23T	3.0	2.9	
Tawa	LM23T	3.0	2.9	
Titahi Bay	LMT	3.0	3.0	
Wainuiomata	LMT	3.0	3.0	
Waikowhai Street	LMT	4.0	2.9	
Evans Bay	LMVP	5.0	2.8	
Gracefield	LMVP	5.0	2.9	
Karori	LMVP	5.0	2.9	

Table 7-20 Health-Criticality Scores for Zone Substation Switchboards

Outcome of the Asset Health Analysis

Frederick Street

The Reyrolle LMT switchboard at Frederick Street had had a number of stages of PD mitigation work since 2015. Initial Transient Earth Voltage (TEV) testing indicated that this work had been successful and though the full PD retesting in 2016 confirmed this, it also showed adjacent circuit breakers with high PD levels that have been masked previously. Further PD mitigation works will occur on these adjacent circuit breakers in 2020 involving the two-breaker incomer for power transformer T2. 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 had PD mitigation work done in 2016. Similarly to Frederick Street, after full PD retesting adjacent circuit breakers were revealed to also have high PD levels. PD mitigation works for these adjacent circuit breakers was completed in 2019 and testing has since confirmed that this work had been successful.

Johnsonville

PD testing at this substation has identified potential issues with CB10 as well as a VT compartment. The VT compartment is being replaced and will be sent back to the manufacturer for investigation.

Mana and Hataitai

The partial discharge at these sites is suspected to be due to a guide bar on LMVP trucks not being earthed. The installation of a leaf spring is expected to resolve this issue.

Renewal and Refurbishment

WELL's fleet of zone substation circuit breakers is generally in good condition. 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 2025-2030, 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 inspections and maintenance.

Significant projects for the renewal of zone substation circuit breakers over the next 12 months are listed in Table 7-21.

Project	Description
Frederick Street	Completion of partial discharge mitigation on the Frederick Street T2 incomer.

Table 7-21 Zone Substation Circuit Breaker Projects for 2020/21

Expenditure Summary for Zone Substation Circuit Breakers

Table 7-22 details the expected expenditure on zone substation circuit breakers by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Partial Discharge Mitigation	250	250	-	-	-	-	-	-	-	-
Switchboard Replacement	-	-	-	-	-	-	-	-	-	-
Capital Expenditure Total	**250**	**250**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Preventative Maintenance	96	96	96	96	96	96	96	96	96	96
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**116**	**116**	**116**	**116**	**116**	**116**	**116**	**116**	**116**	**116**

Table 7-22 Expenditure on Zone Substation Circuit Breakers
($K in constant prices)

7.5.2.3 Zone Substation Buildings and Equipment

Fleet Overview

There are 27 zone substation buildings, three major 11 kV switching station buildings, and two load control buildings at Transpower's Melling and Haywards substations. 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 7-11. The average age of the buildings is 48 years. There are five locations where WELL does not own the land under the zone substation and has a long-term lease with the landowner.

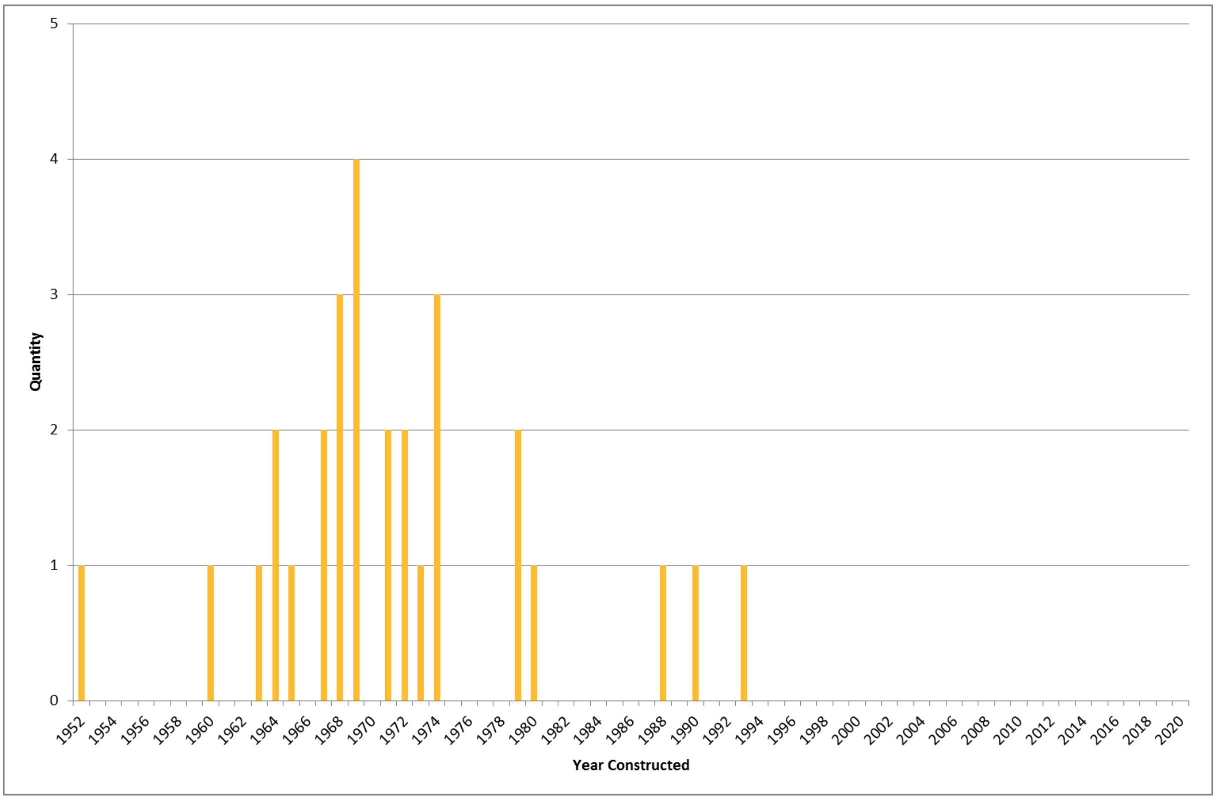


Figure 7-11 Age Profile of Major Substation Buildings

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for zone substation buildings:

Priority Area	Objective
Safety and Environment	No zone substations to be an earthquake risk.
Network Performance	Ensure weather-tightness to prevent damage to internal equipment.

Table 7-23 Fleet Specific Objectives for Zone 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

Table 7-24 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, WELL 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. WELL 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.

WELL 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 Section 11.

Expenditure Summary for Zone Substation Buildings

Table 7-25 details the expected capex expenditure funded via the DPP allowances on zone substation buildings by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Naenae Zone Substation Seismic Strengthening	-	370	-	-	-	-	-	-	-	-
Reactive Capital Expenditure	200	200	200	200	200	200	200	200	200	200
Capital Expenditure Total	**200**	**570**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Preventative Maintenance	83	83	83	83	83	83	83	83	83	83
Corrective Maintenance	200	200	200	200	200	200	200	200	200	200
Operational Expenditure Total	**283**	**283**	**283**	**283**	**283**	**283**	**283**	**283**	**283**	**283**

Table 7-25 Expenditure on Zone Substation Buildings ($K in constant prices)

7.5.3 Overhead Lines

7.5.3.1 Poles

The total number of poles owned by WELL, including subtransmission distribution lines and low voltage lines, is 39,548. Of this number, 21.8% are wooden poles and 77.7% are concrete poles. The remaining 0.5% of poles are fibreglass or steel. Another 16,360 poles are owned by other parties but have WELL assets such as cross arms and conductors attached, for example telecommunication poles owned by Chorus, or the poles owned by Wellington City Council. A summary of the poles either owned by WELL, or with WELL assets attached, is shown in Table 7-26.

Pole Owner	Wood	Concrete/Other	Total
WELL	8,611	30,937	39,548
Customer	6,400	637	7,037
Chorus	6,592	311	6,903
Wellington City Council	1,384	1,036	2,420
Total	**22,987**	**32,921**	**55,908**

Table 7-26 Summary of Poles

The average age of concrete/ other poles is 27.8 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 40.2 years and nearly 47% of all wooden poles are older than 45 years (the standard asset life of wooden poles). Cross arms are predominantly hardwood. WELL has recently approved the use of lighter composite poles on the network for use in areas with difficult access that requires hand carrying of replacement poles. There is also an ongoing trial of composite cross arms underway.

An age profile of poles owned by WELL is shown in Figure 7-12.

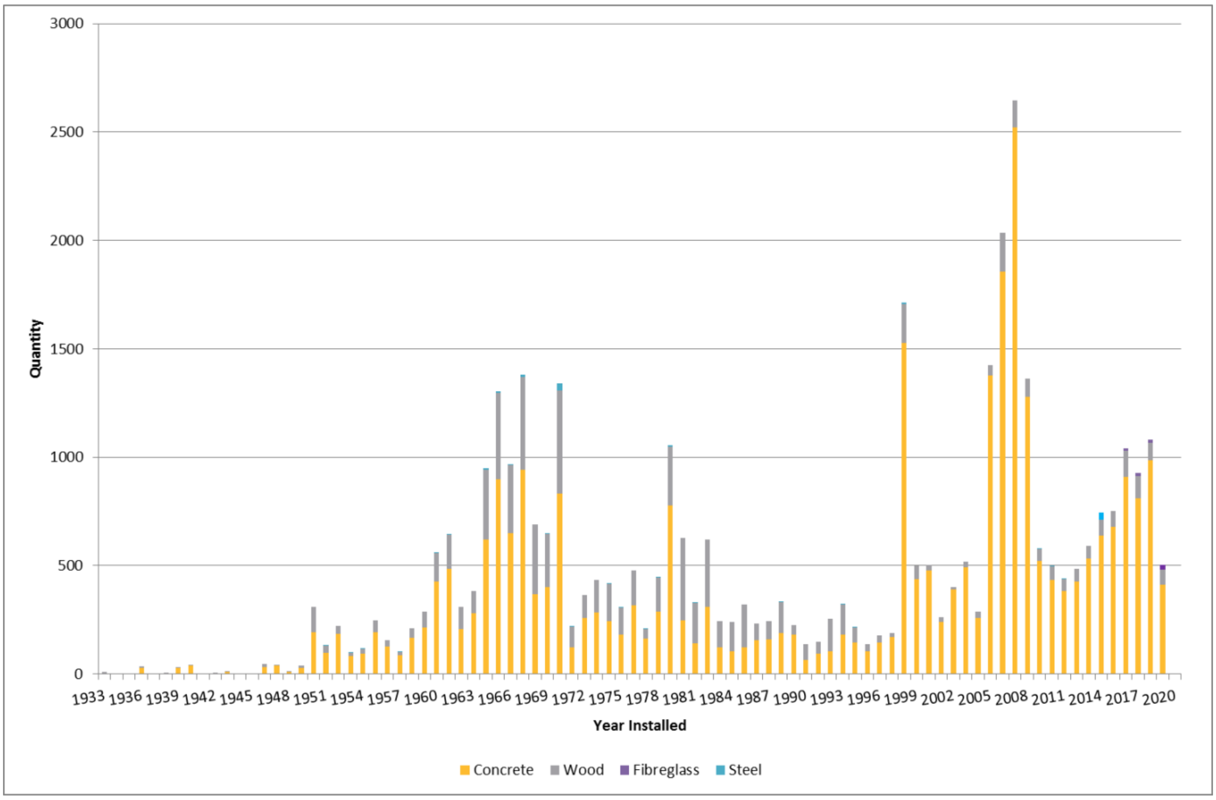


Figure 7-12 Age Profile of Poles

As WELL does not own customer service lines or poles, 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.

WELL has an interest in customer poles that are considered as works as defined in the Electricity Act 1992. An example is for a pole supplying multiple consumers along a private right of way. WELL occasionally replaces customer/private poles in agreement with the original pole owner. WELL then takes responsibility for the ongoing testing and maintenance of the new poles.

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

7.5.3.2 Subtransmission Lines

WELL's 57km of 33 kV 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 is shown in Figure 7-13.

Category	Quantity
33 kV Overhead Line	57km

Table 7-27 Summary of Subtransmission Lines

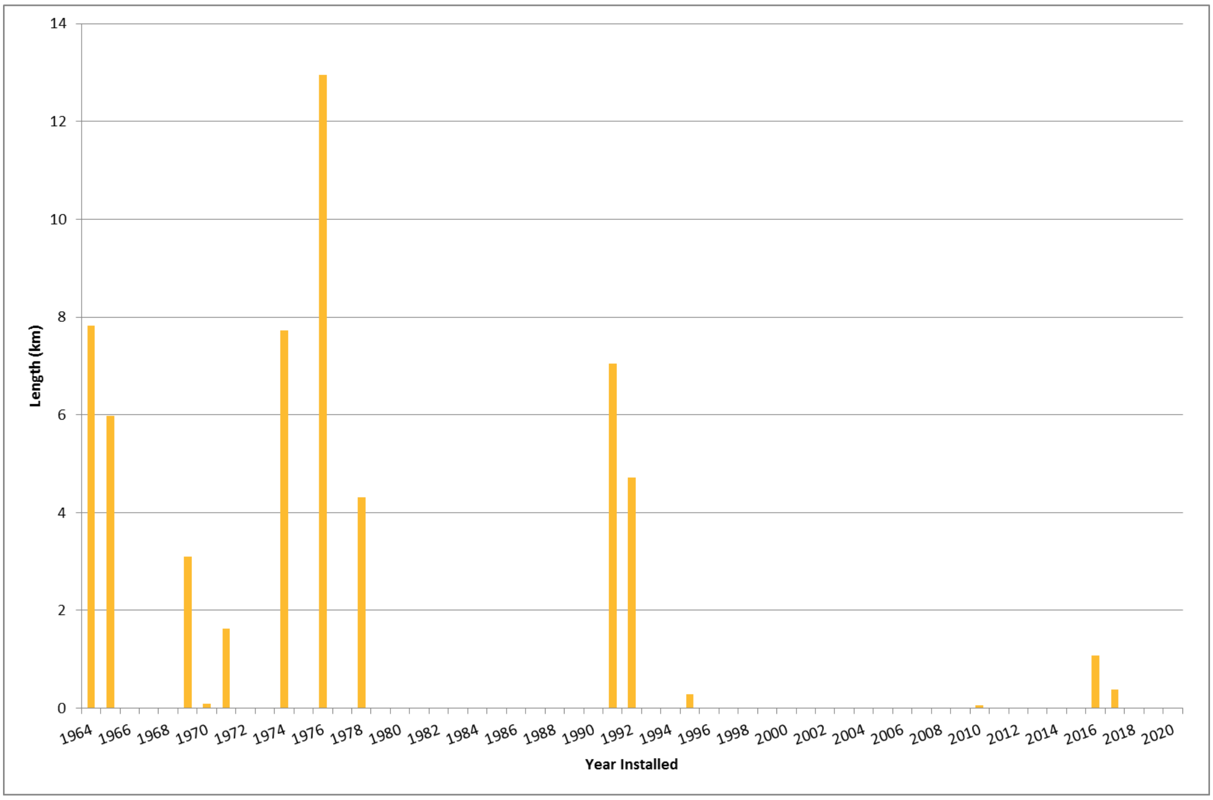


Figure 7-13 Age Profile of Subtransmission Line Conductors

7.5.3.3 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 giving them greater corrosion resistance than standard ACSR with a galvanised steel core. New line reconstruction utilises all aluminium alloy conductor (AAAC). Small sections of covered conductor (CCT) have been used in locations with a history of outages due to windborne debris. 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 7-14 shows the age profile of overhead line conductors.

Category	Quantity
11 kV Line	590km
Low Voltage Line	1,078km
Streetlight Conductor	810km

Table 7-28 Summary of Distribution Overhead Lines

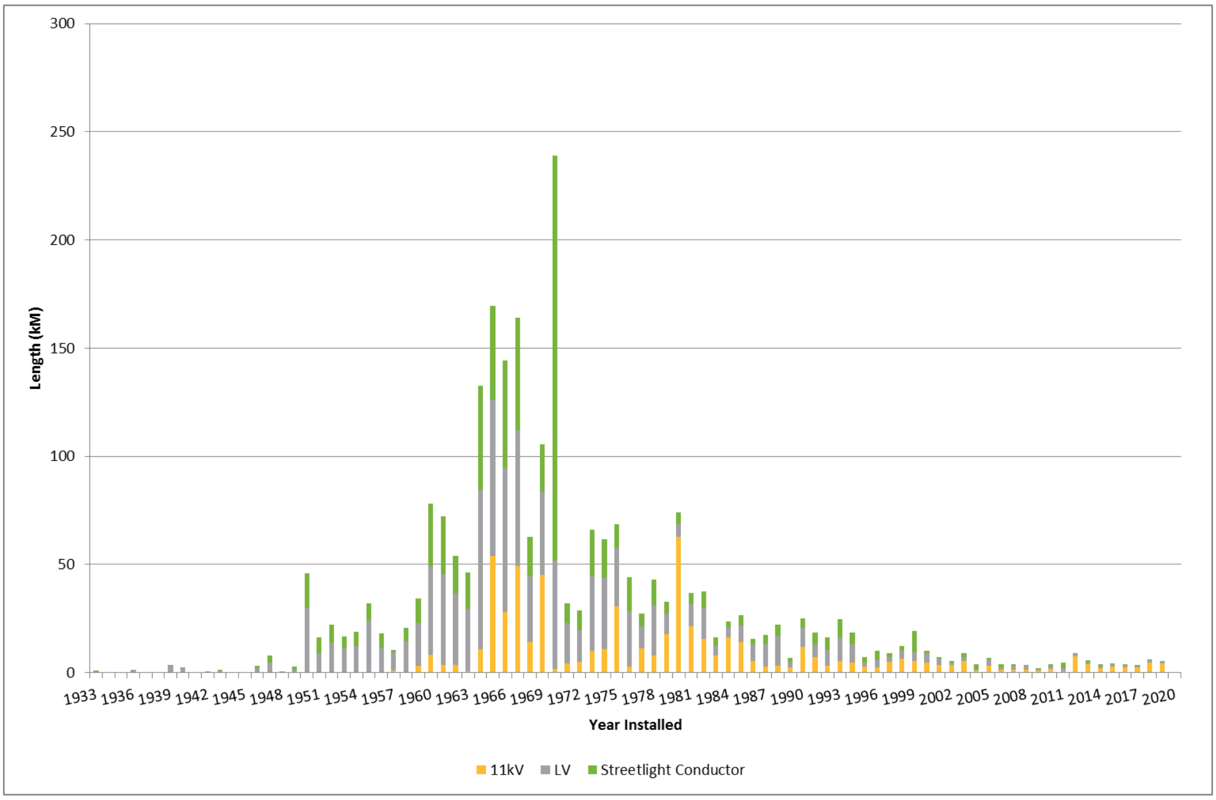


Figure 7-14 Age Profile of Distribution Overhead Line Conductors

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the pole and overhead line fleets:

Priority Area	Objective
Safety and Environment	No injuries/fatalities resulting from working on and around poles. Zero unassisted pole failures.
Customer	Ensure customers are aware of their responsibilities regarding privately-owned poles.
Network Performance	Avoid outages due to pole failure.

Table 7-29 Fleet Specific Objectives for Pole and Overhead Line Fleets

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, steel pole and composite 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

Table 7-30 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 cross arms 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 cross arms.

The replacement of conductor is determined on the lengths of conductor identified as having deteriorated to the criteria for replacement, as a result of annual inspections and analyses. This has historically used a visual based criteria and historical failure rates. Assessment is moving to using a condition-based replacement profile as more destructive testing results become available and can be used to better assess the actual condition and estimate the remaining life of in-service conductor. A programme of destructive testing of conductor samples taken off the network has been put in place from 2018 onwards to determine the remaining life based on tensile strength, ductility and level of corrosion. An initial sample of 10 conductors has been tested thus far, with a further of 80 samples to be done.

Pole Condition

WELL 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 provides remaining life indicators and an assessment of the suitability of the pole to support the mechanical loading being applied to it. Approximately 2,000 poles are Deuar tested every year.

The majority of poles on the WELL network are in good condition. Approximately three-quarters of the poles installed in the Wellington area are concrete, which are durable and in good condition. The majority of 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 which are leaning, have head splits or incur third party damage, 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. WELL has a standard that governs third party attachments to network poles. This standard will ensure future connections to poles for telecommunications infrastructure meet WELL'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 7-15 shows the health-criticality matrix of WELL's fleet of poles. Pole asset health is determined by the pole's condition, while asset criticality is determined by the voltage of the lines connected to the pole and the number of consumers that they supply.

		Lowest Impact		**Asset Criticality**			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0	18	10	8	4			
	1.5							
Asset Health	2.0	544	116	153	59		1	
	2.5							
	3.0	10,940	2,144	2,392	664	21	50	
	4.0	7,066	1,036	1,377	548	4	33	
Best Health	5.0	7,366	1,821	2,334	822	7	10	

Figure 7-15 Pole Health-Criticality Matrix

The forecast future condition of the pole fleet is modelled using survival curves. Figure 7-16 shows the survival curves for poles and crossarms. The survival curves for poles are derived from the age at which poles have been tagged. There is currently insufficient data to forecast the expected end of life for concrete poles. The survival curve for crossarms is based on the age at which a crossarm is identified as having a defect that requires replacement of the arm.

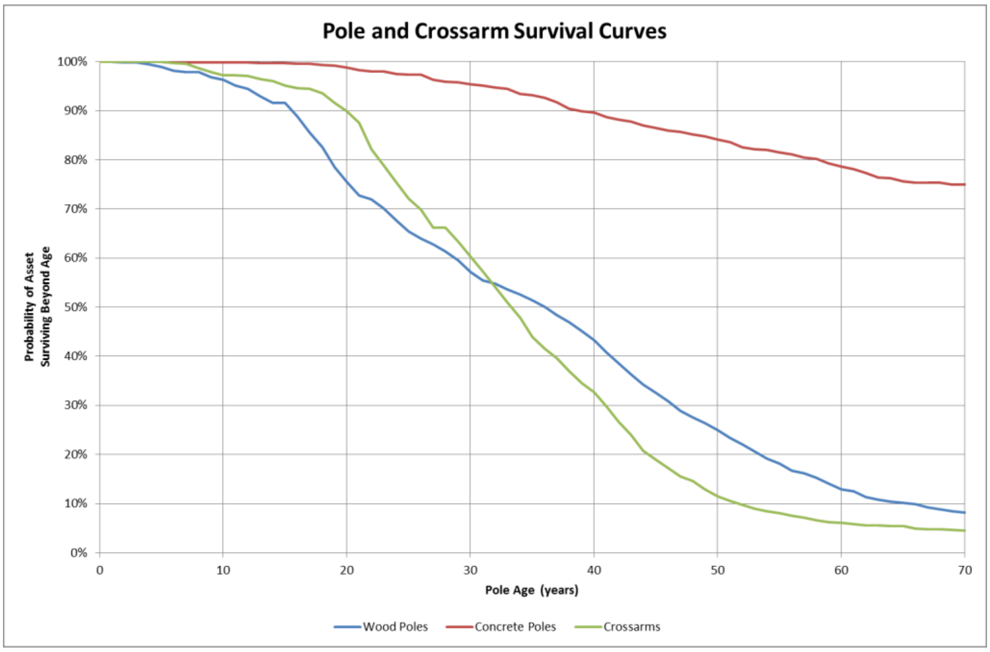


Figure 7-16 Pole and Crossarm Survival Curves

Overhead Line Condition

Pin type insulators are no longer used for new 33 kV or 11 kV line construction as they develop reliability issues later in life such as split insulators due to pin corrosion, or leaning on cross arms 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, when cross arms require replacement or during feeder reliability improvement projects. 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. A number of Fargo sleeve type automatic line splices have failed in service. These sleeves were only suitable for a temporary repair. The failure mode for Fargo sleeves is likely to be vibration related and can cause feeder faults when exposed to high vibrations. Fargo sleeves are no longer used on the network and are replaced with full tension compression sleeves as they are found. Alternatively the span will be re-conductored if the joints are not suitably located for replacement.

Failure modes and effect analysis undertaken in 2016 and 2017 have shown that most of the failures classified as conductor failures were actually connector failures. This has resulted in an extensive review of the connector fleet installed on the overhead network. The result of this review is a deeper understanding of the rate of ageing that has occurred on connectors within the WELL network. The increased rate of ageing due to the proximity of overhead circuits to marine salt pollutants has resulted in the approval of protective gel coverings for wedge type connectors to protect them from accelerated deterioration due to exposure to the elements. These connectors get a protective covering whenever they are installed and all existing installations are reviewed when work is being done to be either replaced with a covering or to have a covering installed.

The forecast future condition of the overhead line conductor and connector fleet is modelled using failures per kilometre of conductor installed. Figure 7-17 shows the failure rates for conductors, jumpers, and connectors.

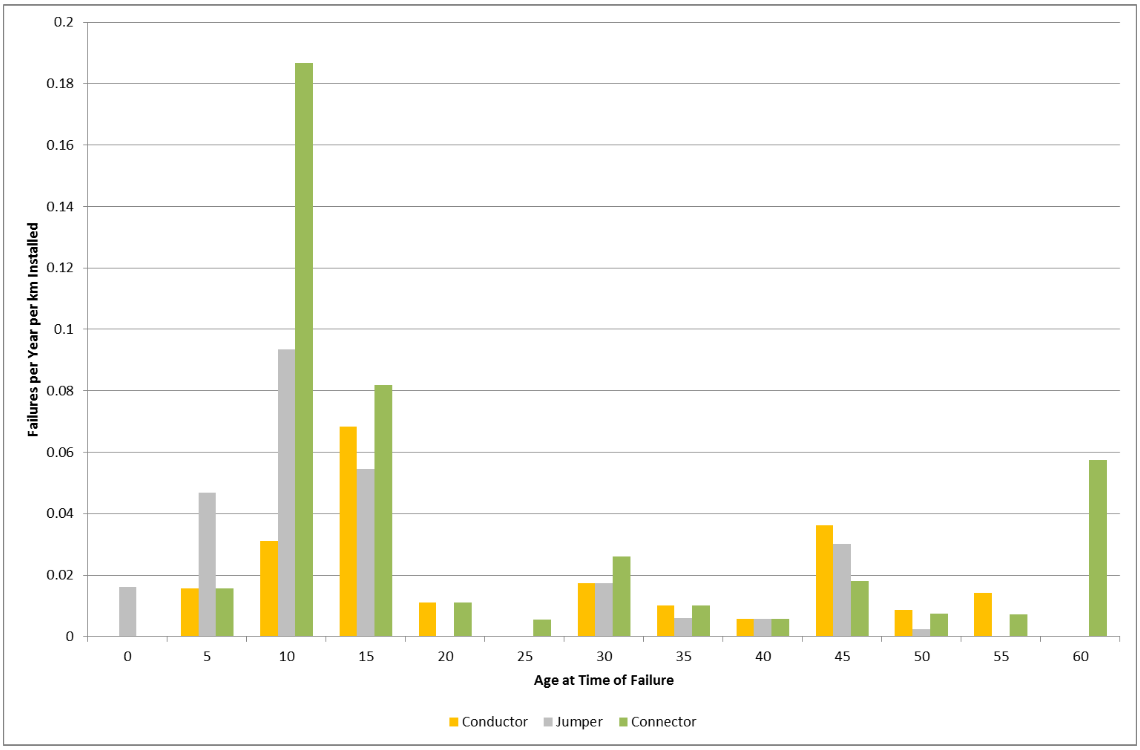


Figure 7-17 Overhead Conductor and Connector Failure Rate by Age

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.

WELL is currently assessing options for extending the life of wooden poles. In 2017 it conducted a trial of pole reinforcement technology with the reinforcement of nine yellow tagged poles. The purpose of this trial was to assess suitability of reinforcement under Section 41(3)(b) of the Electricity (Safety) Regulations 2010 as a means of deferring pole replacement until multiple poles in the same area require replacement, in particular seeking efficiency in pole replacement costs. The reinforced poles are being monitored through inspection and Deuar testing in order to gain confidence in the technology before any decision is made about whether to adopt reinforcement as an option to assist with managing the fleet.

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 or composite poles for weight, access constraints or loading design. Poles on walkways and hard to reach areas are normally replaced with light softwood poles or composite poles because they can be carried in by hand. Cranes are used where practicable but have limited reach in some areas of Wellington. WELL does not normally favour the use of helicopters in erecting poles due to the cost and the need to evacuate residents around the pole location.

The required number of pole replacements per year is forecast by rolling the population through the survival curves, to estimate the number of poles reaching end of life each year. The replacement rate of poles is forecast to decline until 2035 as the population of wooden poles is progressively replaced with concrete poles, before increasing as the older concrete poles start reaching end of life. As noted earlier, there is significant uncertainty in the model for the expected life of concrete poles, and this forecast will continue to be updated in coming years in order to improve the prediction of when this increase will occur.

Renewal and Refurbishment – Lines

Since 2009, WELL 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, Karori, Wainuiomata and Korokoro have been progressively re-conductored, 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.

The rate of conductor failure shows that an extensive conductor replacement programme is not required within the period of this Plan, aside from work targeted at Feeder Reliability Improvement as identified in Section 6.

The relatively large number of failures occurring in the 5-20 year age bracket has been identified as being due to corrosion of Ampact wedge connectors, causing the connector to fail or the jumper/conductor to fail at the point of connection. This has been addressed through the instruction to fit Gelpact covers to any exposed Ampacts when undertaking planned work on the pole.

Significant projects for the renewal of overhead lines over the next 12 months are listed in Table 7-31.

Project	Description
Gracefield Feeders	Line refurbishment of Gracefield 2 and 8
Haywards Feeders	Line refurbishment of Haywards 2842
Karori Feeders	Line refurbishment of Karori 3
Mana Feeders	Line refurbishment of Mana 6
Plimmerton Feeders	Line refurbishment of Plimmerton 11
Porirua Feeders	Line refurbishment of Porirua 9
Seaview Feeders	Line refurbishment of Seaview 6 and 12
Takapu Road – Tawa	Line refurbishment of Takapu Road – Tawa circuits A and B.
Brown Owl 8 Recloser	New recloser at the urban-rural boundary of Brown Owl 8

Table 7-31 Overhead Line Projects for 2020/21

Expenditure Summary for Overhead Lines

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Feeder Reliability Projects	2,455	1,842	2,017	2,013	2,013	2,155	2,199	2,244	2,290	2,400
Pole Replacement Programme	6,602	6,335	6,587	6,415	6,156	6,074	6,157	6,015	5,644	5,596
Reactive Capital Expenditure	850	850	850	850	850	850	850	850	850	850
Capital Expenditure Total	**9,907**	**9,027**	**9,454**	**9,278**	**9,019**	**9,079**	**9,206**	**9,109**	**8,784**	**8,846**
Preventative Maintenance	485	480	473	467	460	454	451	451	452	451
Corrective Maintenance	575	575	575	575	575	575	575	575	575	575
Operational Expenditure Total	**1,060**	**1,055**	**1,048**	**1,042**	**1,035**	**1,029**	**1,026**	**1,026**	**1,027**	**1,026**

Table 7-32 Expenditure on Overhead Lines
($K in constant prices)

7.5.4 Distribution and LV Cables

Fleet Overview

WELL'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 11 kV primary ring configuration, with short 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 11 kV underground distribution system has normally open interconnections between radial feeders, and feeders are segmented into small switching zones using locally operated ring main switches. In the event of a cable fault, the faulted cable section can be isolated and supply to downstream consumers can be switched to neighbouring feeders.

Category	Quantity
11 kV cable (incl. risers)	1,181km
Low Voltage cable (incl. risers)	1,712km
Streetlight cable	1,113km

Table 7-33 Summary of Distribution Cables

Approximately 87.5% of the underground 11 kV cables are PILC and PIAS and the remaining 12.5% 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 7-18.

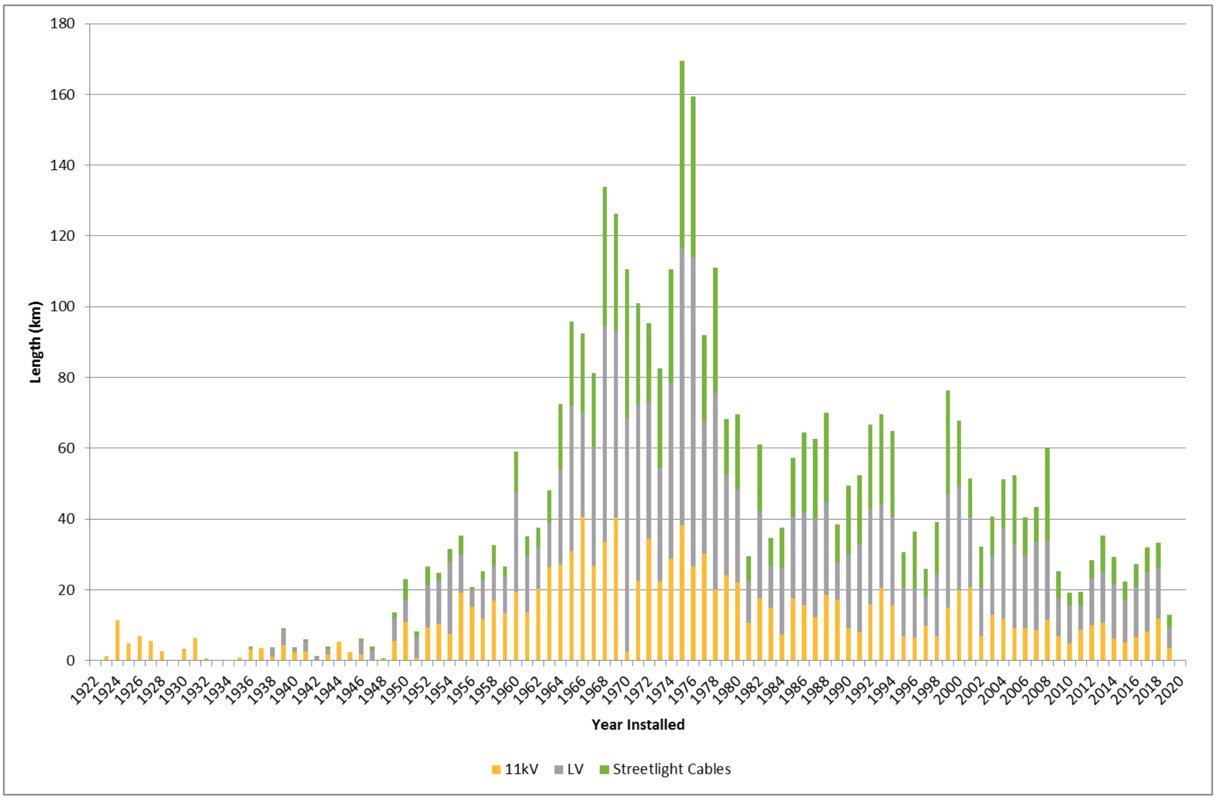


Figure 7-18 Age Profile of Distribution Cables

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for the distribution cable fleet:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around 11 kV and LV cables.
Customer	Mitigate risk of potential decrease in service or price shock caused by under-forecast of cable replacement required. Avoid repeat 11kV outages due to cable condition.
Cost	Reduce cable replacement costs.

Table 7-34 Fleet Specific Objectives for Distribution Cable Fleets

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 replaced in sections. A proactive maintenance regime up to this point has not been considered 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.

WELL has been trialling cable testing technology by testing poor performing cables with a variety of diagnostic tools. The purpose of this trial is to gain sufficient understanding of the results produced by these tools and match them to actual cable performance to provide confidence of their suitability as a condition assessment tool to:

- Determine whether a tested cable needs to be pro-actively replaced (either in total or to a targeted section);
- Build a predictive model, and
- Forecast future replacements.

The cable testing trials undertaken to date are listed in Table 7-35.

Year	Testing
2016/17	Online PD testing of Central Park 33kV cables, Haywards 11kV cables and one distribution cable.
2017/18	Further online PD testing of Haywards 11kV cables and three distribution cables.
2018/19	DAC-PD and VLF-TD testing of 60 Seaview Rd and Hutt Rec A 11kV cables. VLF-PD testing of Haywards 11kV cables.
2019/20	VLF-PD testing of eight distribution cables.

Table 7-35 Cable Testing Trials

It is too early in the programme to make asset management decisions based on the cable test results, so the findings to date relate to the suitability of testing technology and understanding the relationship between test results and future cable performance.

Distribution Cable Condition

Underground cables usually have a long life and high reliability as they are not subjected to environmental hazards however, as these cables age, 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.

Figure 7-19 shows the health criticality matrix for WELL's fleet of 11kV cable, by cable length.

		Lowest Impact		**Asset Criticality**				Highest Impact
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
	1.5							
Asset Health	2.0	7	14	5		9		15
	2.5							
	3.0	22	25	55		23		55
	4.0	119	285	193		56		15
Best Health	5.0	79	99	100		15		4

Figure 7-19 11 kV Cable Health-Criticality Matrix (km)

The forecast future condition of the distribution cable fleet is modelled using failures per unit installed, with a cable unit being defined as the network average segment length of 330m, to allow a direct comparison between the failure rates of cables and their accessories. Figure 7-20 shows the failure rates for cables, joints, and terminations.

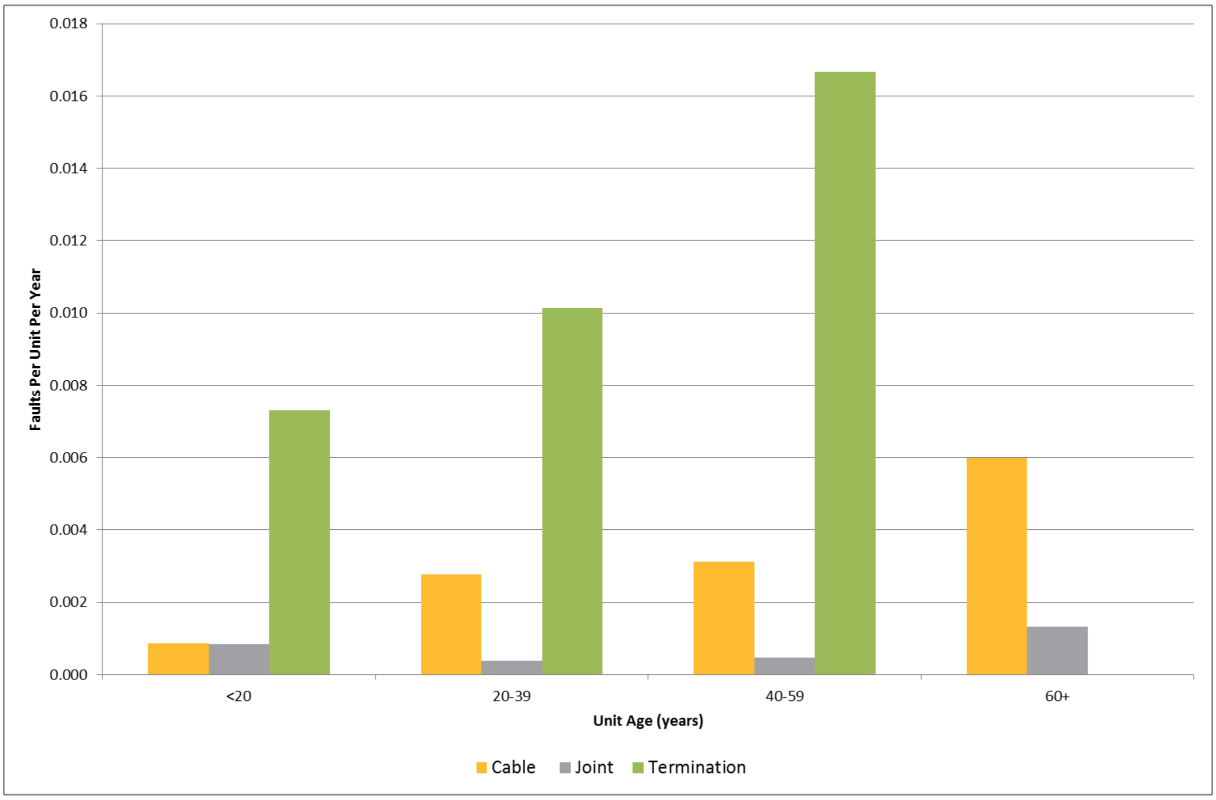


Figure 7-20 11 kV Cable Failure Rate by Age

Renewal and Refurbishment

The failure rate data indicate that terminations are clearly the weakest component of the cable system, with age-based deterioration apparent in the failure rates. However, failure rates for the oldest terminations are still relatively low at 1.7%/year. Cable termination replacement is driven by visual inspection when signs of discharge or significant compound leaks are found, and when thermography scans indicate hot connections. Further predictive analysis methods will be investigated in 2020.

There is also a trend of increased rates of cable failure by age from 60 years onwards, but the failure rate is not high enough to indicate that significant lengths of cable are at end of life. The decision to replace rather than repair a cable is currently based on a combination of fault history and frequency, together with the results of tests undertaken after earlier cable fault repairs.

It is recognised that the distribution cable fleet is ageing and will require a programme of renewal at some point in the future. The cable condition modelling is currently signalling that the rate of cable replacement may need to increase in the latter half of the planning period in order to maintain historical levels of underground network reliability. Refinement of the model is required to provide greater certainty to this estimate, and to provide a framework for cost-effective renewal targeted at the cables at highest risk of failure.

Expenditure Summary for Distribution and LV Cable

Table 7-36 details the expected expenditure on distribution and LV cable by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Asset Replacement and Renewal Capex	398	500	500	500	500	1,500	1,500	3,000	3,000	3,000
Reactive Capital Expenditure	363	370	375	381	389	395	402	409	416	423
Capital Expenditure Total	**761**	**870**	**875**	**881**	**889**	**1,895**	**1,902**	**3,409**	**3,416**	**3,423**
Corrective Maintenance	150	150	150	150	150	150	150	150	150	150
Operational Expenditure Total	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**

Table 7-36 Expenditure on Distribution and LV Cable ($K in constant prices)

7.5.5 Distribution Substations

7.5.5.1 Distribution Transformers

Fleet Overview

Of the distribution transformer population, 59% are ground mounted and 41% 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 200 kVA. The ground-mounted units are three phase units rated between 100 and 1,500 kVA. WELL holds a variety of spare distribution transformers to allow for quick replacement following an in-service failure. 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 coastal, a transformer may not reach this age due to corrosion. The age profile of distribution transformers is shown in Figure 7-21.

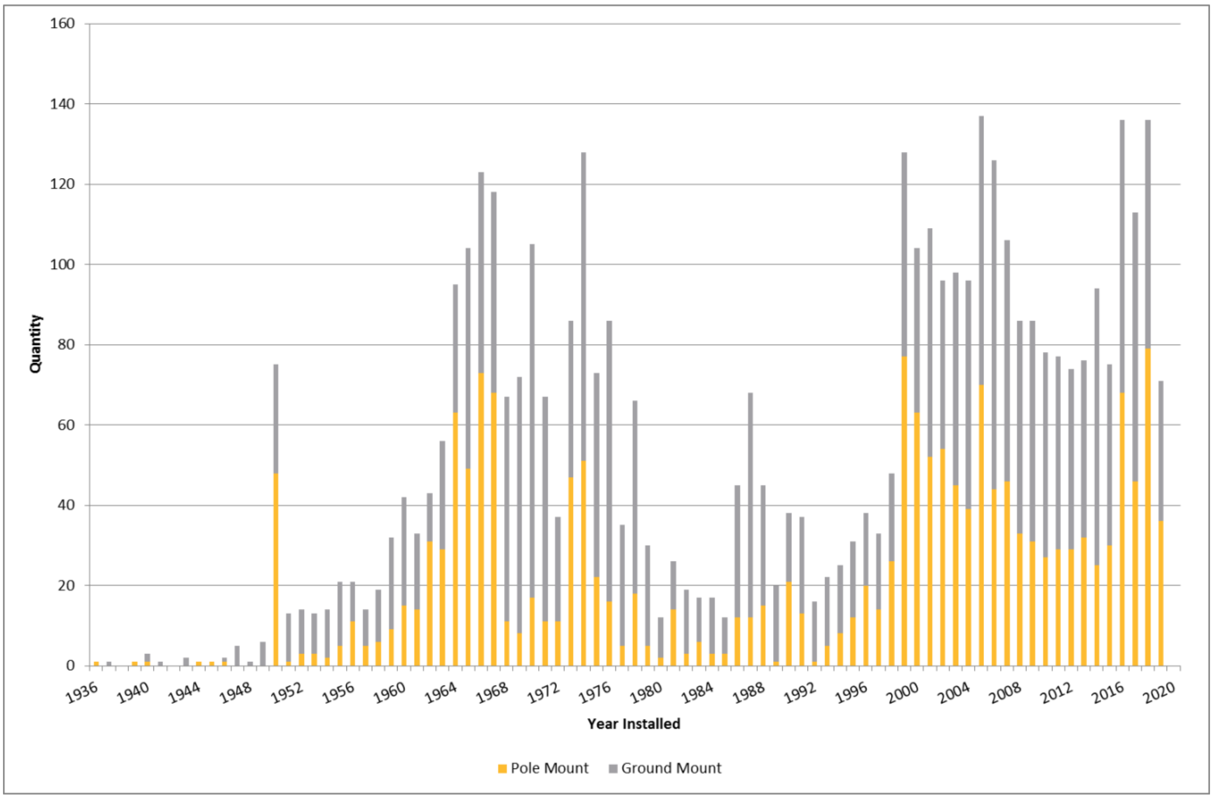


Figure 7-21 Age Profile of Distribution Transformers

In addition to pole and integral pad mount berm substations, WELL owns 555 indoor substation kiosks and occupies a further 674 sites that are customer owned (typically of masonry or block construction or outdoor enclosures). A summary of WELL's distribution transformers and substations is shown in Table 7-37.

Category	Quantity
Distribution transformers	4,373
Customer owned Distribution transformers	25
Distribution transformers – Total	**4,398**
WELL owned substations	3,741
Customer owned substations	674
Distribution substations – Total	**4,415**

Table 7-37 Summary of Distribution Transformers and Substations

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for distribution transformers and substations:

Priority Area	Objective
Safety and Environment	No distribution substations to be earthquake prone. Substations located in road reserve to not be a risk to public safety.
Customer	Meet customer needs for provision of information relating to transformers installed inside their buildings.
Network Performance	Ensure weather-tightness to prevent damage to internal equipment.

Table 7-38 Fleet Specific Objectives for 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

Table 7-39 Inspection and Routine Maintenance Schedule for Distribution Transformers

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 1999, with 46 such units currently in service. Many of these transformers have internal 11 kV 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.

Distribution Transformer Condition

Figure 7-22 shows the health-criticality matrix of WELL's fleet of distribution transformers, including both pole-mounted 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 consumers 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	1	1					
	2.0	14	30	48	5	1		
Asset Health	3.0	290	523	1,096	279	349	232	
	4.0	218	362	528	151	46	27	
Best Health	5.0	27	56	75	31	2		

Figure 7-22 Distribution Transformer Health-Criticality Matrix

The forecast future conduction of the distribution transformer fleet is modelled using survival curves. Figure 7-23 shows the survival curves for ground and pole mounted distribution transformers. These curves are based on the age at which a transformer is identified as having a defect that is best resolved through transformer replacement.

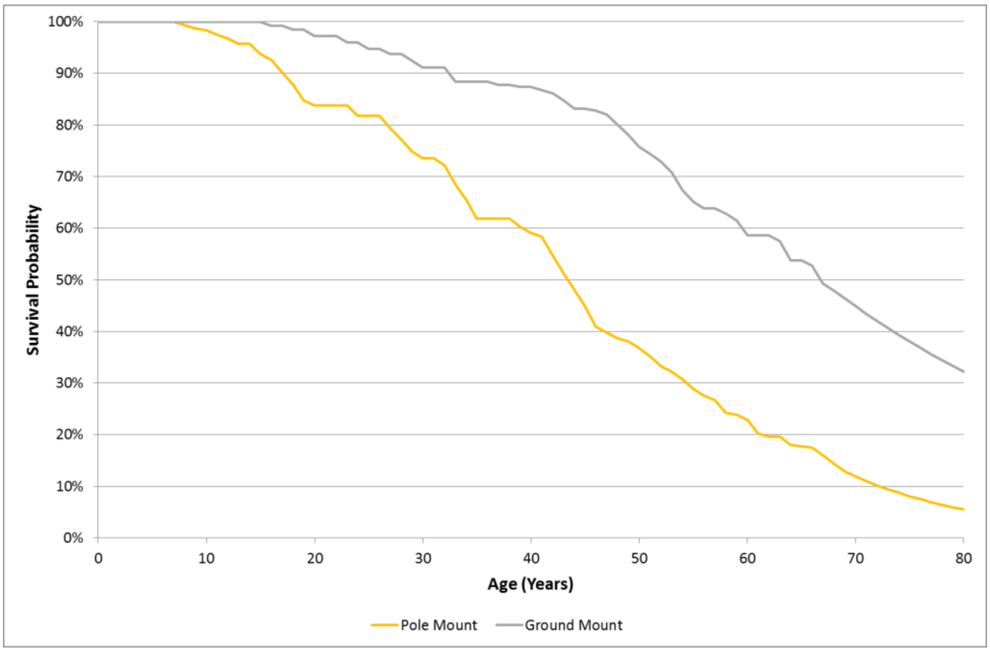


Figure 7-23 Distribution Transformer Survival Curves

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 failures are investigated to determine the cause. This assessment determines if the unit is to be repaired, refurbished, or scrapped depending on cost and residual life of the unit. Typical condition issues include rust, heavy insulating fluid 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 and is driven by condition.

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.

WELL 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 mean integral substations are still sometimes 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.

Significant projects for the renewal of distribution substations over the next 12 months are listed in Table 7-40.

Project	Description
Newtown Substation	Seismic strengthening and transformer replacement at Newtown Substation

Table 7-40 Distribution Substation Projects for 2020/21

Expenditure Summary for Distribution Substations

Table 7-41 details the expected expenditure on distribution substations by regulatory year. The capitalised lease capex item relates to the new accounting standard that now treats operating leases as a capital item. The capitalised lease items relate to leased land and property for substations.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Seismic Strengthening	1,167	330	300	650	-	-	-	-	-	-
Earthing Upgrades	300	300	300	300	300	300	300	300	300	300
Asset Replacement and Renewal Capex	1,724	1,208	1,263	1,290	2,200	2,700	2,700	2,700	2,700	2,700
Reactive Capital Expenditure	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825	1,825
Capitalised Leases	316	134	43	-	11	-	-	-	-	-
Capital Expenditure Total	**5,332**	**3,797**	**3,731**	**4,065**	**4,336**	**4,825**	**4,825**	**4,825**	**4,825**	**4,825**
Preventative Maintenance	515	515	515	515	515	515	515	515	515	515
Corrective Maintenance	470	470	470	470	470	470	470	470	470	470
Operational Expenditure Total	**985**	**985**	**985**	**985**	**985**	**985**	**985**	**985**	**985**	**985**

Table 7-41 Expenditure on Distribution Substations ($K in constant prices)

7.5.6 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 were discussed in Section 7.5.2. There are 1,292 distribution circuit breakers and 2,418 other ground-mounted switches in the WELL network. 11 kV circuit breakers are used in the 11 kV distribution network to increase the reliability of supply in priority areas such as in and around the CBD and they are also used as protection when installing transformers 750kVA and above. 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 7-24 and Figure 7-25.

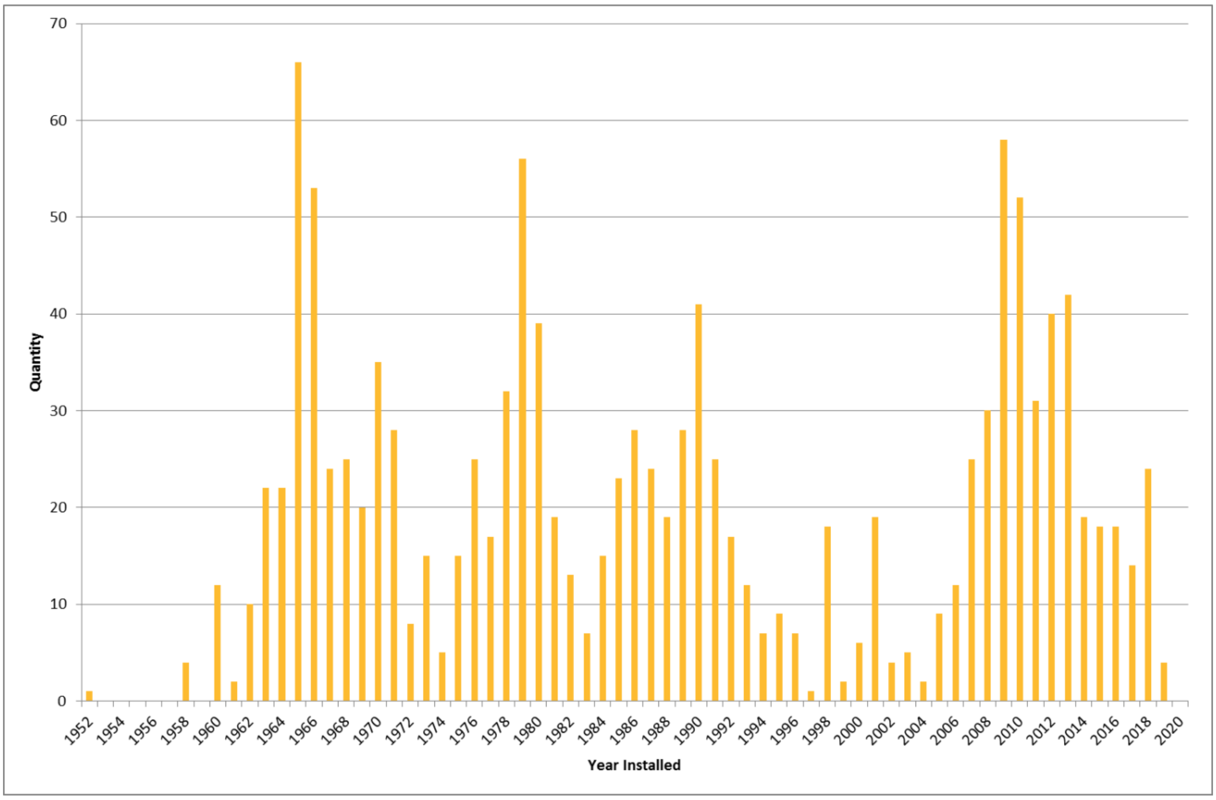


Figure 7-24 Age Profile for Distribution Circuit Breakers

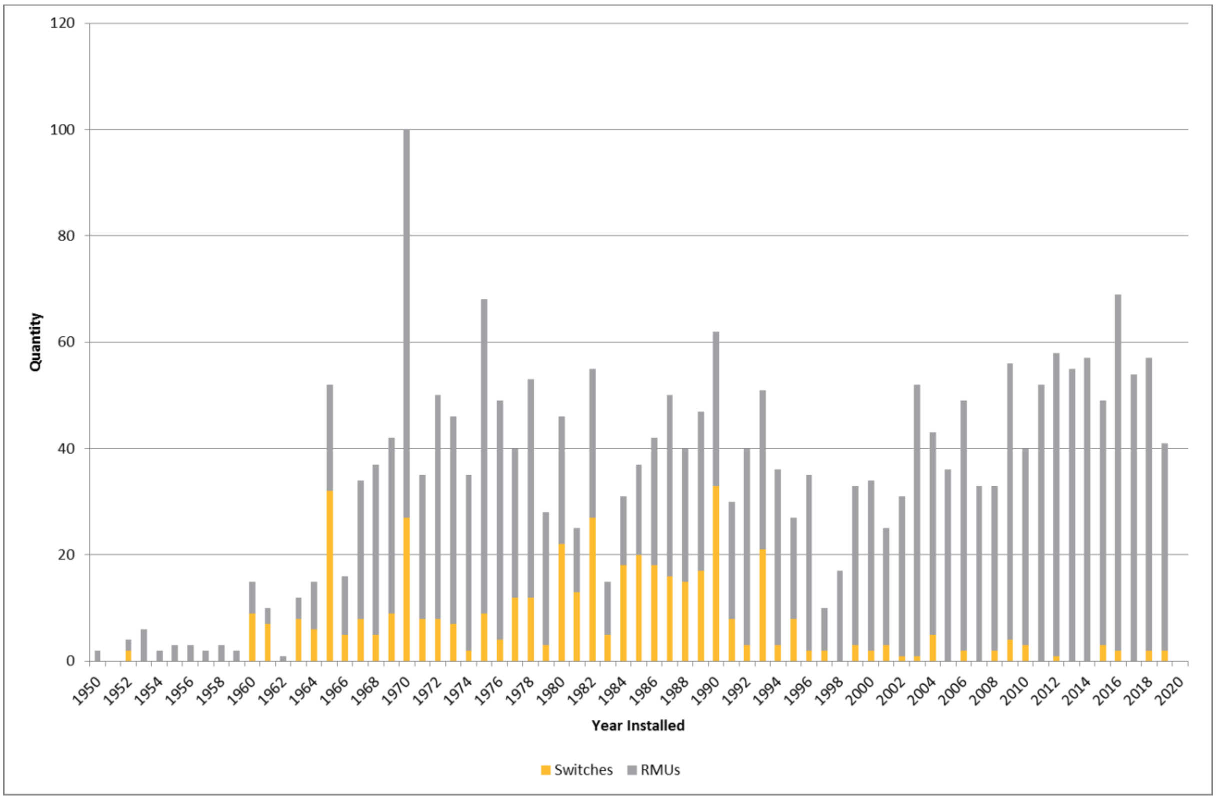


Figure 7-25 Age Profile of Other Ground Mounted Distribution Switchgear

The average age of distribution circuit breakers in the network is around 31 years, while the average age of ring main units 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 Table 7-42 and Table 7-43.

Category[33]	Quantity
Distribution Circuit Breakers	1,292
Oil Insulated Switches	375
Oil Insulated RMUs	189
SF_6 Insulated Switches	90
SF_6 Insulated RMUs	765
Resin Insulated RMUs	994

Table 7-42 Summary of Ground Mounted Distribution Switchgear

Manufacturer	Breaker Type	Quantity
ABB	SF_6	27
AEI	Oil	48
BTH	Oil	54
Crompton Parkinson	Oil	1
GEC/Alstom	Oil	52
Hawker Siddeley	Vacuum	21
Merlin Gerin / Schneider	SF_6	336
	Vacuum	9
Reyrolle	Oil	625
	Vacuum	59
South Wales	SF_6	36
Statter	Oil	22[34]
Total		**1,292**

Table 7-43 Summary of Distribution Circuit Breakers by Manufacturer

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for ground mounted distribution switchgear.

[33] There is a switchgear reclassification which contributed to the changes in quantities.
[34] This is for circuit breakers only and excludes the HV switches and ring main units.

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around distribution switchgear.
Network Performance	Distribution switchgear to be safe to operate live, to minimise customer impact during switching.

Table 7-44 Fleet Specific Objectives for Ground Mounted Distribution Switchgear

Maintenance Activities

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

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.	Triggered by Inspection Results
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.	7 yearly
11 kV 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

Table 7-45 Inspection and Routine Maintenance Schedule for Distribution Switchgear

Distribution Switchgear Condition

The switchgear installed on the WELL network is generally in good condition and comprises both oil and gas insulated ring main units, as well as solid resin insulated equipment. Routine maintenance addresses the majority of minor defects and requires replacement when the condition deteriorates to a point that is no longer cost effective to repair. 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 7-26 shows the health-criticality matrix of WELL'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 11 kV feeder that the unit is connected to.

		Lowest Impact		Asset Criticality			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0			6				
	1.5	29	49	199	36	5	7	
Asset Health	2.0							
	2.5	87	232	524	193	278	196	
	3.0	93	140	508	88	402	228	
	4.0	14	28	77	13	44	37	
Best Health	5.0	18	13	57	19	10	10	

Figure 7-26 Distribution Switchgear Health-Criticality Matrix

Specific condition issues for distribution switchgear are:

Schneider Ringmaster

A number of Schneider Ringmaster Ring Main Units (RMUs) have suffered gas depressurisation while in service. The first recorded loss of gas occurred in 2011 after about 10 years in service. These have been identified as only affecting the RMUs and not the circuit breakers. The affected RMUs are manufactured between 2000 and 2005 and 144 of these units are currently in service in the WELL network. The loss of gas also affects other EDBs in New Zealand. The cautious monitoring of the gas levels before operating the RMUs has been reinforced to switching staff.

The manufacturer has identified that the most likely cause of failure is stress fractures in the resin gas tank moulding due to temperature cycling, combined with a higher gas pressure being used for RMUs over the affected period. Schneider does not believe the failure to be related to the design of the switchgear.

Solid Insulation Magnefix

In 2019 WELL set up a working group that included service providers and industry experts to investigate potential application of preventative maintenance optimisation to Magnefix switchgear. During the maintenance of Magnefix units there is often very little required to be done beyond cleaning the unit and checking that the contacts are in good order. In-service failures are rare, with previous failures largely being attributed to either issues with cable terminations or occurring during operating. This indicates that if a unit is functioning properly and is in good condition then it can be expected to continue functioning without being removed from service for maintenance. The Magnefix investigation determined that the need for maintenance of Magnefix switchgear can be satisfactorily predicted through visual, thermal, and partial discharge inspections, rather than being purely time-based, reducing the need to switch these units and allowing maintenance resource to be prioritised to maintenance of oil-filled switchgear.

Older Magnefix units have grease-filled termination boxes. Thermal cycling of the units can result in the grease migrating into the cable, potentially compromising the phase-to-phase insulation inside the termination. These units are identified through the routine inspection programme, and operational restrictions are placed on them prohibiting live operation until outages can be arranged to top up the grease to the appropriate level.

There are also 13 sites with Krone KES 10 switchgear, which is also of solid insulation design. These are replaced when the condition deteriorates to a point where repair and maintenance are no longer cost effective.

Long and Crawford

As at October 2019, there are eight Long and Crawford RMUs in service, installed between 1960 and 1996. These are installed in outdoor cage substations often subject to harsh environments. Other networks have experienced catastrophic failures of Long and Crawford fuse switches. WELL has imposed operational restrictions on Long and Crawford fuse switches to prevent the fuse compartments being opened while the switchgear is alive. A programme to replace Long and Crawford RMUs commenced in 2016, for completion during the 2022 calendar year.

Statter

As at October 2019, there are 45 sites with Statter switchgear, with 114 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 nearing 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 a large number of consumers. These will be replaced with modular secondary class circuit breakers to maintain reliability levels. There is an ongoing programme for the replacement of Statter switchgear which is planned for completion in the 2023 calendar year.

<u>Renewal and Refurbishment</u>

HV Distribution Switchgear (Ground Mounted)

As noted above, this section excludes zone substation circuit breakers, which are discussed in Section 7.5.2.2.

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, WELL has an ongoing refurbishment and replacement programme for other ground mounted distribution switchgear.

Oil insulated switchgear is no longer installed, with vacuum or gas (SF6) insulated types now being used. WELL has also recently approved the use of newer types of solid insulation ring main units. In rare cases, when any switchgear device fails, the reason for the failure is studied and a 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 are being replaced based on the risk assessment for that type.

Significant projects for the renewal of ground mounted switchgear over the next 12 months are listed in Table 7-46.

Project	Description
Donald Street Substation	Replacement of 11kV circuit breakers.
Johnsonville Pumps Substation	Replacement of 11kV circuit breakers.

Table 7-46 Ground Mounted Switchgear Projects for 2020/21

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 Southern region 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 2016, WELL prohibited live work between the transformer bushings and the low voltage busbars, and work in situations where items may contact live busbars. This has been followed up with further work to detail an Arc Flash Policy which was reviewed in 2018 to align to the Arc Flash Guideline published by the EEA.

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

Table 7-47 details the expected expenditure on ground-mounted switchgear by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Long and Crawford Replacement Programme	208	389	201	-	-	-	-	-	-	-
Statter Replacement Programme	1,659	1,541	1,886	2,042	964	-	-	-	-	-
Partial Discharge Mitigation	-	300	300	300	300	300	300	300	300	300
Other Asset Replacement and Renewal Capex	596	-	-	-	1,900	3,000	3,000	3,000	3,000	3,000
Reactive Capital Expenditure	400	400	400	400	400	400	400	400	400	400
Capital Expenditure Total	**2,863**	**2,630**	**2,787**	**2,742**	**3,564**	**3,700**	**3,700**	**3,700**	**3,700**	**3,700**
Preventative Maintenance	510	510	510	510	510	510	510	510	510	510
Corrective Maintenance	400	400	400	400	400	400	400	400	400	400
Operational Expenditure Total	**910**	**910**	**910**	**910**	**910**	**910**	**910**	**910**	**910**	**910**

Table 7-47 Expenditure on Ground-mounted Switchgear ($K in constant prices)

7.5.6.1 Low Voltage Pits and Pillars

Fleet Overview

Pillars and pits provide the point for the connection of customer service cables to the WELL 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 1,172 LV units (link pillars, pits, cabinets and boards) in service on WELL'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 Table 7-48.

Type	Quantity
Customer service pillar	8,966
Customer service pit	2,268
Link pillars, pits and cabinets	1,172
Total	**12,406**

Table 7-48 Summary of LV Units

An age profile of LV Units (pillars, pits, cabinets and boards) is shown in Figure 7-27.[35]

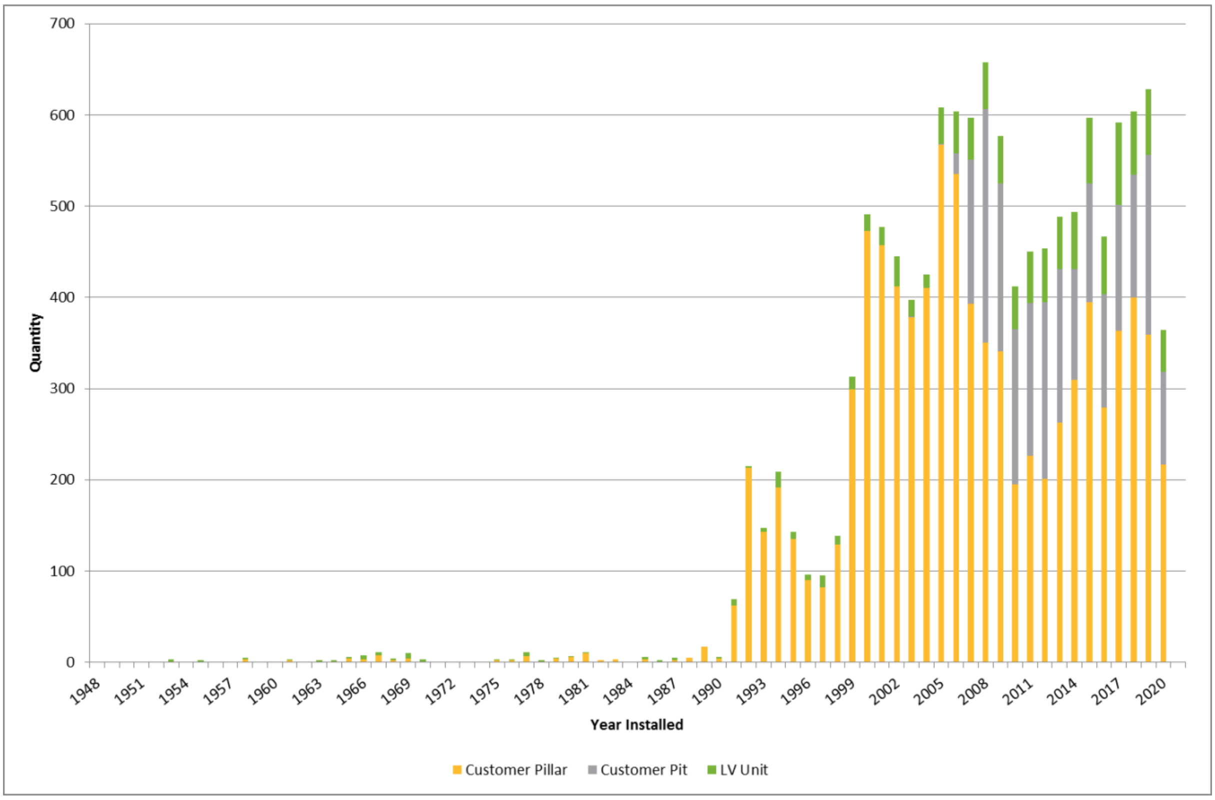


Figure 7-27 Age Profile of Pillars, Pillars and Cabinets

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for low voltage equipment:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around LV units. LV units located in Road Reserve to not be a risk to public safety.

Table 7-49 Fleet Specific Objectives for Low Voltage Equipment

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:

[35] There are 6,119 low voltage pillars, pits, cabinets and LV boards that have unknown installation dates and these have not been included in the age profile.

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

Table 7-50 Inspection and Routine Maintenance Schedule for LV Pits and Pillars

WELL 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 are 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

Table 7-51 details the expected expenditure on low voltage pits and pillars by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Asset Replacement and Renewal Capex	150	150	150	150	150	150	150	150	150	150
Reactive Capital Expenditure	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Capital Expenditure Total	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**	**1,550**
Preventative Maintenance	100	100	100	100	100	100	100	100	100	100
Corrective Maintenance	185	185	185	185	185	185	185	185	185	185
Operational Expenditure Total	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**	**285**

Table 7-51 Expenditure on Low Voltage Pits and Pillars ($K in constant prices)

7.5.7 Pole-mounted Distribution Switchgear

7.5.7.1 Reclosers and Gas Switches

Fleet Overview

Automatic circuit reclosers are pole mounted circuit breakers that provide protection for the rural 11 kV overhead network. The majority of the 16 reclosers on the network are vacuum models with electronic controllers, with only two being older hydraulic types. The individual types of auto-reclosers are shown in the Table 7-52.

Manufacturer	Insulation	Model	Quantity
G&W	Solid/Vacuum	ViperS	14
Reyrolle	Oil	OYT	1
McGraw-Edison	Oil	KFE	1
Total			**16**

Table 7-52 Summary of Recloser Types

The age profile of WELL's reclosers is shown in Figure 7-28.

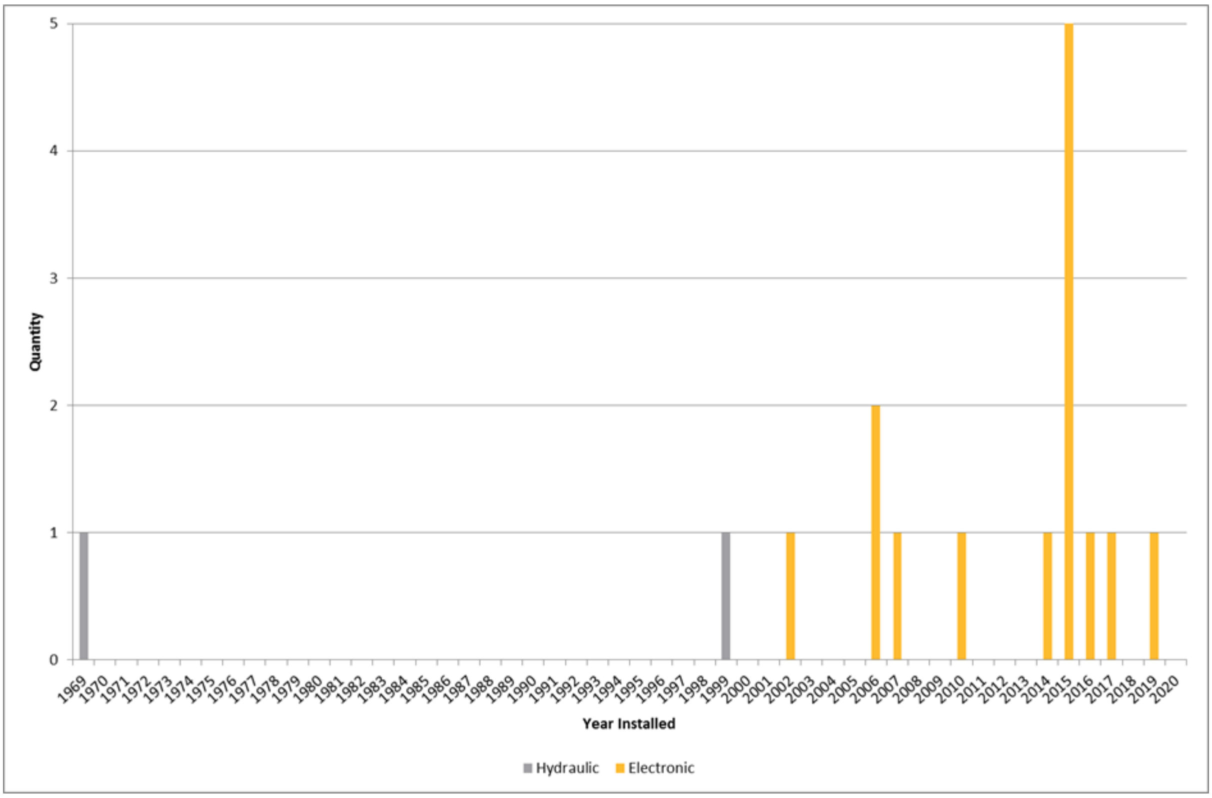


Figure 7-28 Age Profile of Reclosers

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for reclosers:

Priority Area	Objective
Safety and Environment	Ensure use of reclosing complies with best industry practice for public safety.
Customer	Ensure reclosers are functioning correctly to minimise customer disruption.

Table 7-53 Fleet Specific Objectives for 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 hydraulic recloser, inspect and maintain contacts, change oil as required, prove correct operation.	3 yearly
Inspection and Testing of Batteries	Routine visual inspection of batteries, chargers and associated equipment inside electronic recloser control panel. Discharge test of batteries to confirm health	1 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

Table 7-54 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 proved ineffective at returning failed hydraulic reclosers to effective service, and units have proactively been replaced with electronic reclosers, with the final two units planned for replacement during 2020.

Due to the high number of consumers being interrupted under fault conditions, the number of reclosers installed on the system was reviewed in 2018 with a view to increasing the amount installed. A standard defining the optimal number and placement of sectionalising devices such as reclosers was published in 2018 which will assist in defining these numbers going forward.

Expenditure Summary for Reclosers

Table 7-55 details the expected expenditure on reclosers by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Asset Replacement and Renewal Capex	230	-	-	-	-	-	-	-	-	-
Capital Expenditure Total	**230**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Preventative Maintenance	7	8	9	10	11	12	12	13	14	15
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**17**	**18**	**19**	**20**	**21**	**22**	**22**	**23**	**24**	**25**

Table 7-55 Expenditure on Reclosers ($K in constant prices)

7.5.7.2 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 is shown in Table 7-56.

Category	Quantity
Gas Switches	74
Air Break Switches	287
Knife Links	28
Dropout Fuses	2,191
Dropout Sectionalisers	12
Total	**2,592**

Table 7-56 Summary of Pole Mounted Distribution Switchgear

The age profiles of these devices are shown in Figure 7-29.

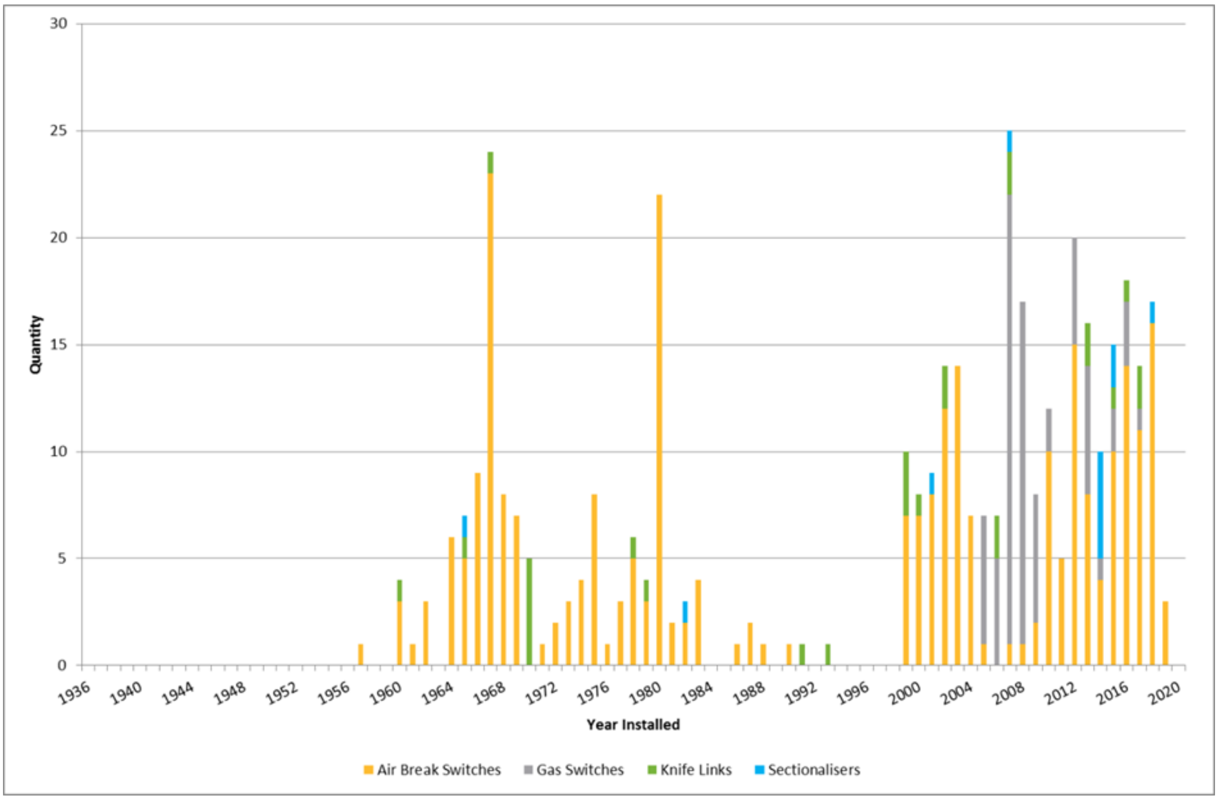


Figure 7-29 Age Profile of Overhead Switchgear and Devices

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has the following fleet-specific objectives for pole mounted switchgear:

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around overhead switchgear. Overhead switchgear located in Road Reserve to not be a risk to public safety.

Table 7-57 Fleet Specific Objectives for Pole Mounted Switchgear

Maintenance Activities

The following routine planned inspection, testing and maintenance activities that are undertaken on overhead switches, links and fuses are shown in Table 7-58.

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

Table 7-58 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 the annual overhead line survey. The large quantity and low risk associated with fuses does not justify an independent inspection and maintenance programme.

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 used.

A problem has previously been identified with in-line links, which started to show signs of failure when used on copper conductor and subjected to fault currents. This situation was monitored over the course of 2017 and a specialist metallurgist was engaged to identify the root cause of failures. The analysis undertaken has shown that the common point of failure has been on temporary links and the application techniques of live line clamps. A temporary suspension on the use of in-line links (and removal of those that were already on the network) was put in place until better quality assurance processes with regards to installation were agreed with the field services provider.

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 and more cost effective solution.

The forecast future condition of the overhead switch fleet is modelled using survival curves, shown in Figure 7-30. The survival curve is based on the age at which switches have been replaced.

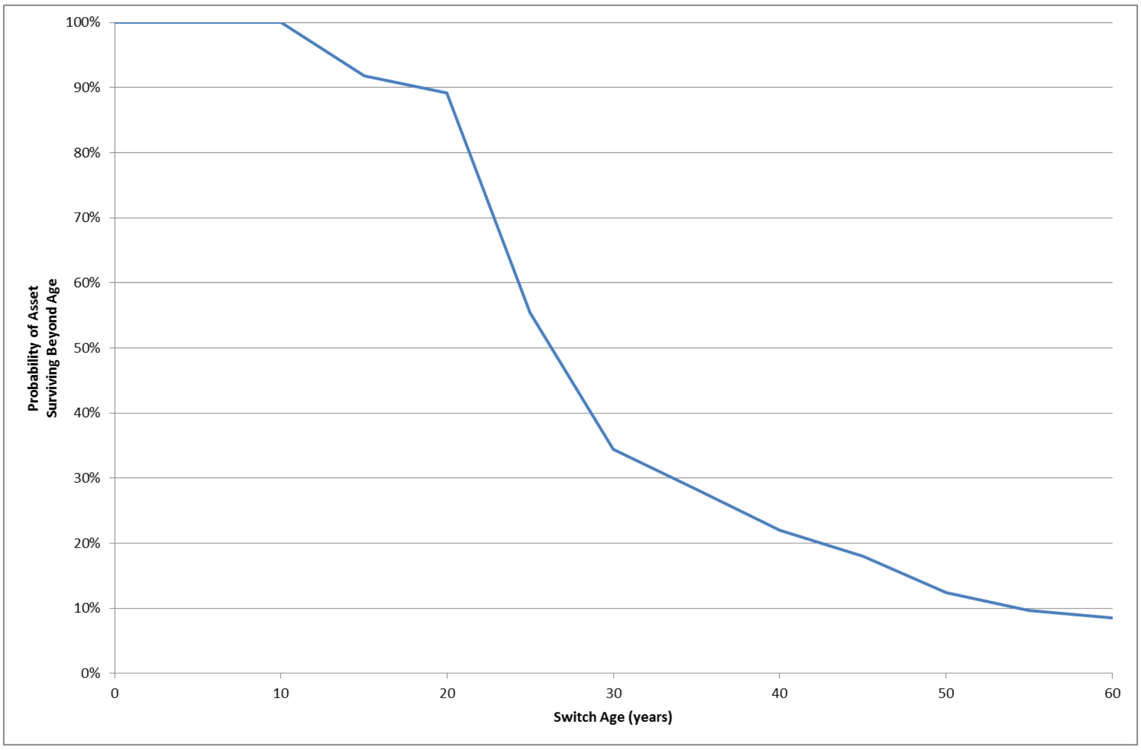


Figure 7-30 Overhead Switch Survival Curve

Renewal and Refurbishment

Any renewal activity on these assets is driven from standard inspection rounds and resultant maintenance activities arise from the identification of corrective work. With the extensive pole and crossarm replacements undertaken over recent years, a large number of overhead switches have now been replaced. Replacement generally occurs as reactive capital expenditure 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.

The forecast number of overhead switch replacements per year is forecast by rolling the population through the survival curve.

Expenditure Summary for Overhead Switchgear

Table 7-59 details the expected expenditure on overhead switchgear by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Reactive Capital Expenditure	71	76	76	81	94	96	100	109	105	102
Capital Expenditure Total	**71**	**76**	**76**	**81**	**94**	**96**	**100**	**109**	**105**	**102**
Preventative Maintenance	140	140	140	140	140	140	140	140	140	140
Corrective Maintenance	30	30	30	30	30	30	30	30	30	30
Operational Expenditure Total	**170**	**170**	**170**	**170**	**170**	**170**	**170**	**170**	**170**	**170**

Table 7-59 Expenditure on Overhead Switchgear (\$K in constant prices)

7.5.8 Other System Fixed Assets

7.5.8.1 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. WELL has a number of historic DC system voltages within its substations, including 24V, 30V, 36V, 48V, and 110V, however 24V has been adopted as the standard 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
10 Second battery discharge test.	10 second battery discharge test for battery banks rated less than 65 Ah, measurement and reporting of results.	Annually
Comprehensive battery discharge test.	Comprehensive battery discharge test for battery banks rated 65 Ah and larger, measurement and reporting of results.	2 yearly

Table 7-60 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.

Battery Replacement

WELL has a total of 543 battery banks across 297 sites. Batteries are a critical system for substation operation, but are low cost items. WELL's policy is that all batteries are replaced at 80% of their design life rather than implementing an extensive testing regime. For sites with higher ampere-hour demand, 10-year life batteries are used. For smaller sites, or communications batteries where the demand is lower, batteries are installed with 5-year lives. As part of primary plant replacements, WELL is standardising the voltages used for switchgear operation as well as communications equipment.

Expenditure Summary for Substation Batteries

Table 7-61 details the expected expenditure on substation batteries by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Asset Replacement and Renewal Capex	210	152	94	111	199	163	116	102	210	152
Capital Expenditure Total	**210**	**152**	**94**	**111**	**199**	**163**	**116**	**102**	**210**	**152**
Preventative Maintenance	57	57	57	57	57	57	57	57	57	57
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**	**67**

Table 7-61 Expenditure on Substation Batteries (\$K in constant prices)

7.5.8.2 Protection Devices

Fleet Overview

Protection devices are assets that automatically detect abnormal conditions and indicate a potential primary equipment fault. This ensures that the system remains safe, stable, and that damage to equipment is minimised whilst service life is maximised. Protection assets are also installed to limit the number of consumers affected by an equipment failure.

On the HV system there are approximately 1,405 protection devices in operation. The majority of these are electromechanical devices. The remainder use solid state electronic or microprocessor technology. Protection devices are generally mounted as part of a substation switchboard but can also be housed in dedicated panels.

WELL has assigned a Tier system to differentiate between the various sections of the distribution network as presented in Figure 7-31. This serves to enable a clear reference for asset management planning and expenditure forecasting. The types of protective devices and their individual applications vary dependant on the level of security required and the risk to supply.

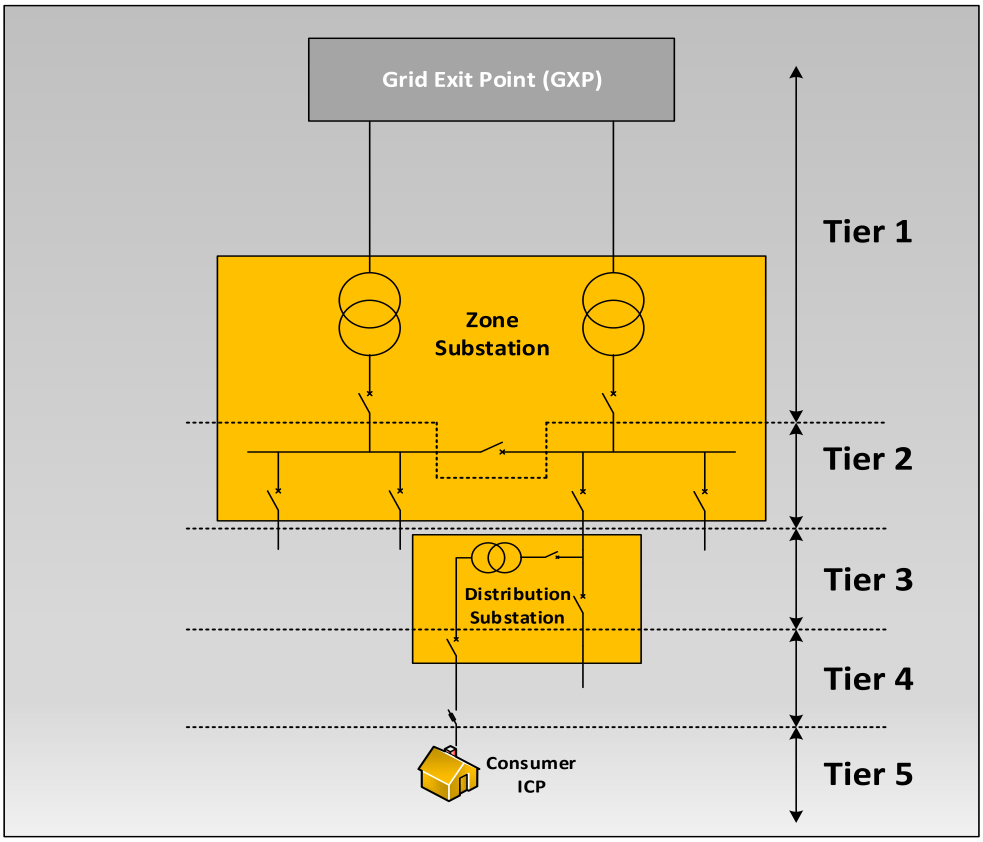


Figure 7-31 WELL Protection Tier System

Differential protection is used on all Tier 1 systems across the network and is also widely used on Tier 2 systems in the Southern Region. This is to provide the optimum level of protection when running a closed ring network topology. 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) protection is employed.

Outside of the Southern Region, Tier 2 is generally enabled with OC/EF protection, supplemented by auto-reclosers on rural feeders.

Fuses are also used for protection of 11kV distribution transformers and other equipment. Fuses are used on the LV system for the protection of cables and LV equipment however these fuses form part of the primary circuit and are not considered 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 set points, as required by the System Operator.

The average age of secondary protection devices on the WELL network is around 40 years with approximately 57% of the assets being more than 40 years old.

The age profiles of these devices are shown in Figure 7-32.

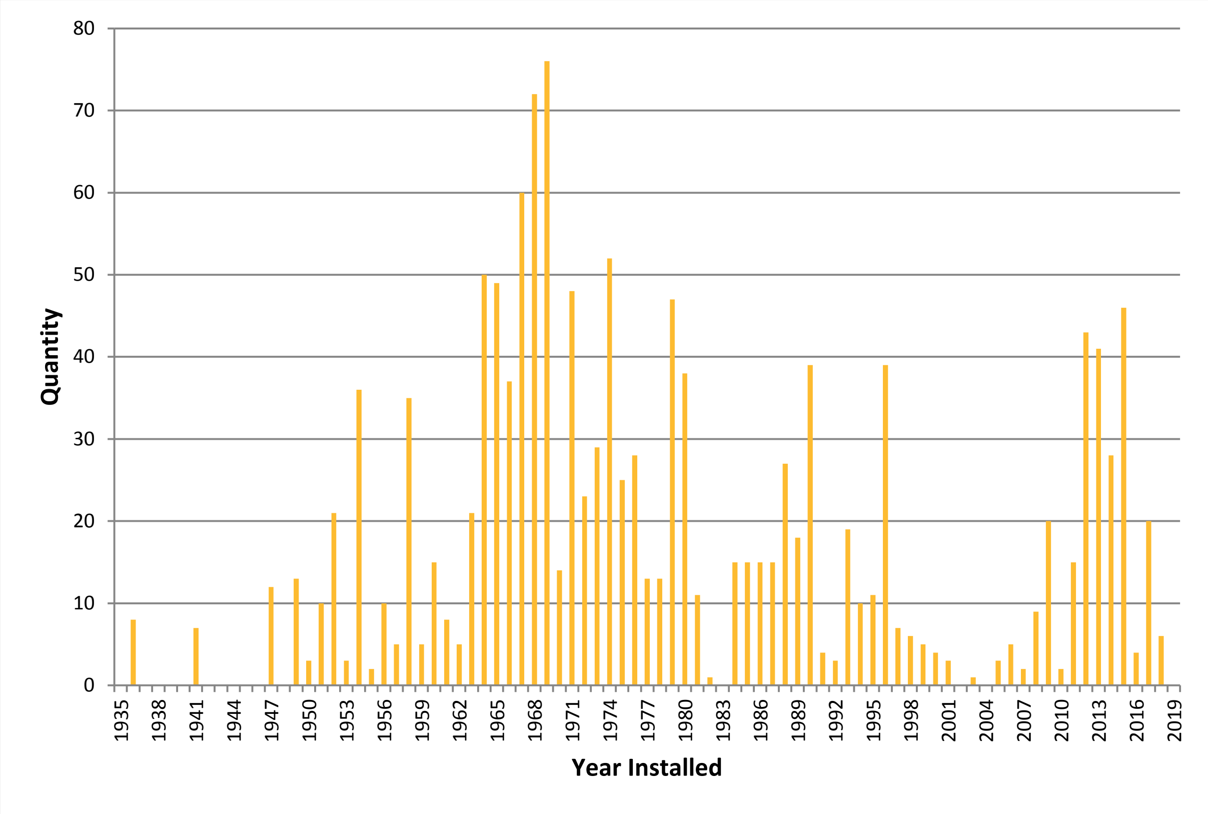


Figure 7-32 Age Profile of Protection Relays

The WELL Network Protection Standard can be referred to for a more detailed account of the protection devices and systems that are used on the WELL network and their application.

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 (Tier 1 & 2) 5 yearly (Tier 3)
Protection Testing for Numerical Devices	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 (Tier 1 & 2) 5 yearly (Tier 3)
Numerical Relay Battery Replacement	Replacement of backup battery in numeric relay.	4 yearly (Tier 1 & 2) 5 yearly (Tier 3)

Table 7-62 Inspection and Routine Maintenance Schedule for Protection Relays

The testing of differential protection also serves to test the copper pilot cables between substations. Upon a failed test, the degree of health is assessed against the requirements of the device type and the protection service is either moved to healthy conductors on the pilot cable or the cable is flagged for repairs. Due to deteriorating outer sheaths on pilot cables, some early pilot cables are now suffering from moisture ingress and subsequent degradation of insulation quality and these are attended to by either moving the pilot routes or repairing and replacing cables.

Numerical relays, although equipped with self-diagnostic functions, are tested in line with the table above. Newer more complex protection schemes need to be tested to ensure the correct functions and logic schemes still operate as expected.

Renewal and Replacement

WELL takes a risk based approach to protection device replacement strategies. Generally, protective devices have a long service life and WELL's fleet is in good condition. Rarely does a protective device fail in-service, and deterioration is identified during routine maintenance testing.

Once a device has been identified as unable to perform its primary function, it is replaced immediately using a critical spare. If the performance is adequate but showing signs of deterioration, the device is earmarked to be included into existing replacement programs. The protection replacement programmes focus on device condition, functionality and the inherent risk posed to the network. Replacement is often coordinated with other projects especially for assets such as switchgear and transformers.

Tier 1 protection, detailed in Figure 7-33, has the highest importance and requires the greatest level of security, therefore has a higher priority for replacement. At the time of primary equipment replacement, if required, the opportunity is taken to upgrade associated protection schemes to meet the current standards. To date, electromechanical devices have provided reliable service and are expected to remain in service for the life of the switchgear they are housed in. For newer numeric devices, it is not expected that they will provide the same length of service as the switchgear.

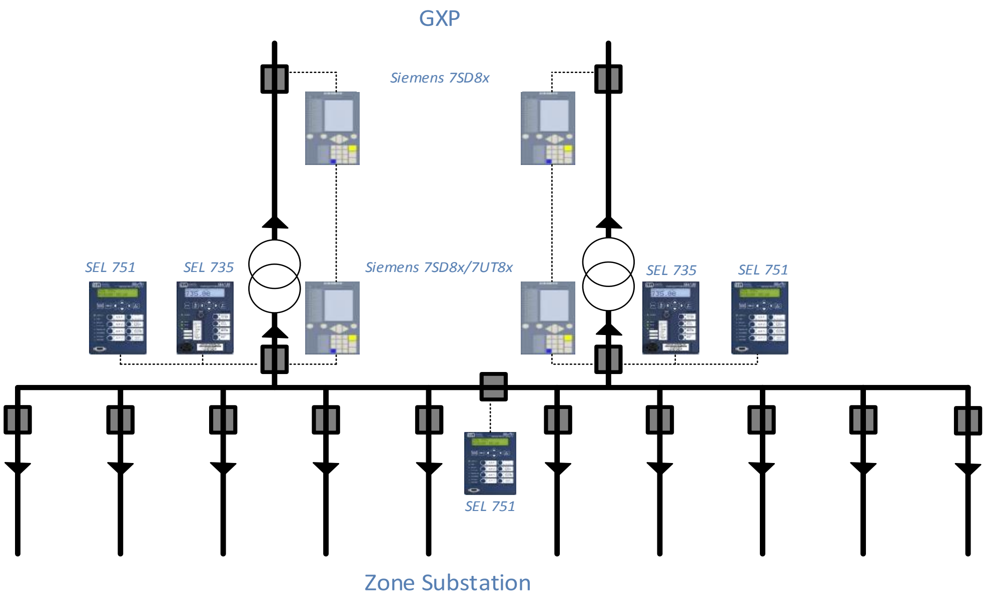


Figure 7-33 Tier 1 Protection Replacement Device Layout

The following programmes and projects are included in the asset replacement[36] and maintenance budgets:

- Ongoing replacement of devices with identified risk;
- Annual preventative maintenance program;
- VIP300 Protection Improvements;
- Tier 1 replacement programme;
- Tier 2 replacement programme; and
- Tier 3 replacement programme.

In addition to replacement programs, WELL is developing a number of supporting documents to aid in its management of protection devices. These are as follows:

- Secondary Assets Network Development Reinforcement Plan (NDRP);
- Network Protection Policy;
- Network Protection Standard; and
- Application guides and testing and commissioning instructions.

Expenditure Summary for Protection Relays

Table 7-63 details the expected expenditure on protection relays by regulatory year.

[36] 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 Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
VIP300 Protection Improvements	80	-	-	-	-	-	-	-	-	-
Brown Owl & Maidstone ZS Tier 1 Replacement	774	-	-	-	-	-	-	-	-	-
Plimmerton & Mana ZS Tier 2 Replacement	-	200	-	-	-	-	-	-	-	-
Tier 1 Replacement Programme	-	-	760	760	760	760	760	380	-	-
Tier 2 Replacement Programme	-	-	-	300	400	300	400	400	600	600
Tier 3 Replacement Programme	-	-	-	-	-	-	-	300	300	300
Capital Expenditure Total	**854**	**200**	**760**	**1,060**	**1,160**	**1,060**	**1,160**	**1,080**	**900**	**900**
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**

**Table 7-63 Expenditure on Protection Relays
($K in constant prices)**

7.5.8.3 SCADA and Communications Assets

Fleet Overview

The WELL SCADA system is comprised of many assets, housed in different locations, and interlinked using several media types. The Master Station is at the top of the topology and there are many other components scaling down to the end device known as the Remote Terminal Unit (RTU). The SCADA Master Station is a GE PowerOn Fusion system, commissioned in early 2016. A legacy Foxboro system has been retained 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 field equipment at any site that has been provisioned for SCADA. 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 field 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 fiber optic cables. Typically the copper pilots are WELL owned while some of the fiber links are WELL owned and others are under lease agreements.

WELL have 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 7-34.

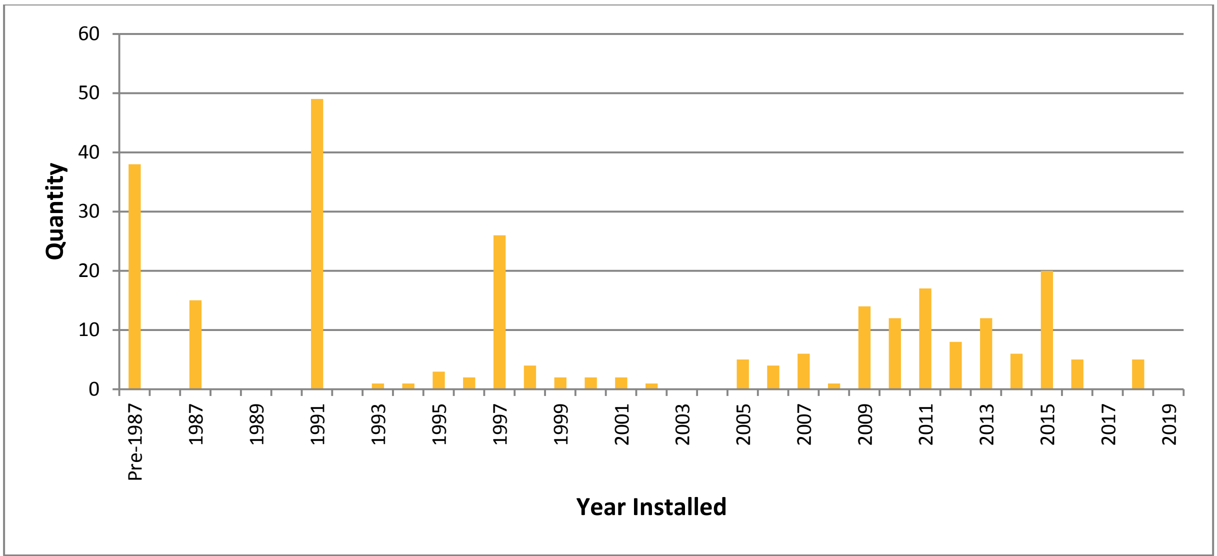


Figure 7-34 Age Profile of SCADA RTUs

To date, WELL has approximately 250 SCADA provisioned sites and is made up of RTUs using several communication protocols from several decades.

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 is provided as required by Wellington based maintenance contractors; and

(b) Software maintenance and support is provided by external service providers.

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 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 selfdiagnostics remotely monitored and have dual redundancy of converters and batteries to provide a high level of supply security in the unlikely event of failure.

SCADA System Component Challenges

SCADA Radio

Analogue radio is still used by WELL to service a small number of sites via the Conitel protocol. Along with the age of equipment and availability of spares, there are a number of constraints to using such a system which include: limited address range, no time stamping, and a diminishing capability of interfacing with devices. A replacement system is being explored as modern radio systems have been identified to be a cost effective and reliable media for SCADA moving forward. This forms part of the larger scale SCADA radio project which will be considered to greatly increase capacity and is detailed in Section 8.

Legacy Remote Terminal Units (RTUs)

There are C225, C5, Dataterm and Miniterm legacy RTUs still in service on the network. These are no longer manufactured and are difficult to repair, so as they fail they are interchanged with modern alternatives or replaced as per an active replacement programme. Power supply failure, IC failure and analogue “jumping” are known consequences of using these RTUs alongside the constraints of their functionality and protocol usage.

Common Alarms

There are 37 Common Alarm units 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 RC02/3 RTU which is widely used on the network.

Cisco 2911 Routers

There are 51 Cisco 2911 routers in service, located in 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 for the addition of VOIP interface cards, the 2911 router is replaced with its modern equivalent and returned to stock as a spare until all units are phased out.

PAS Replacement Project

There are two Siemens Power Automation System (PAS) units that act as a protocol converter between Siemens IEC61850 field devices located at three sites and the DNP3.0 SCADA master station.

The PAS units are now end of life and due for replacement. Consideration is being given to a direct replacement with a modern Siemens PAS and also alternative solutions for providing for the existing functionality. Alternative solutions would further align the affected sites with standard WELL network topology and provide a functionality improvement.

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 identified, with replacement priority being given to the zone and major switching substations.

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 utilising the DNP3.0 protocol.

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 to 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 receiver devices.

The priority of the substation RTU replacement programme will align with other secondary asset replacement programmes. 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.

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

- Zone RTU Replacement Programme;
- Common Alarm Replacement Programme;
- Distribution RTU Replacement;
- Conitel Replacement;
- Cisco Router Replacement;
- PAS Replacement Project; and
- End of Life RTU Replacement (Reactive).

Expenditure Summary for SCADA and Communications Assets

Table 7-64 details the expected expenditure on SCADA and communications assets by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Seaview Zone RTU Replacement	300	-	-	-	-	-	-	-	-	-
Waterloo Zone RTU Replacement	320	-	-	-	-	-	-	-	-	-
Korokoro Zone RTU Replacement	295	-	-	-	-	-	-	-	-	-
Jubilee Rd. RTU Replacement	-	100	-	-	-	-	-	-	-	-
Cisco Router Replacement	-	50	100	-	200	300	-	-	-	-
PAS Replacement Project	-	100	225	-	-	-	-	-	-	-
Zone RTU Replacement Programme	-	640	640	640	320	-	-	-	-	-
Common Alarm Replacement Programme	75	150	75	225	225	225	225	225	225	225
Distribution RTU Replacement Programme	-	-	100	100	100	100	100	100	100	100
Conitel Replacement	-	-	-	-	100	200	500	500	500	500
Reactive Capital Expenditure	100	100	100	100	100	200	200	200	200	200
Capital Expenditure Total	**1,090**	**1,140**	**1,240**	**1,065**	**1,045**	**1,025**	**1,025**	**1,025**	**1,025**	**1,025**
Corrective Maintenance	20	20	20	20	20	20	20	20	19	20
Operational Expenditure Total	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**19**	**20**

Table 7-64 Expenditure on SCADA and Communications Assets
($K in constant prices)

7.5.9 Other Network Assets

7.5.9.1 Metering

WELL does not own any metering assets as these are owned by retailers and metering companies.

Check meters are installed at GXPs, and Maximum Demand Indicator (MDI) meters are installed in a 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. This is further discussed in Section 9.

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 WELL's check meters exceeds an acceptable tolerance.

7.5.9.2 Generators and Mobile Substations

WELL owns six mobile generators and a fixed generator supporting the disaster recovery control room site. WELL makes use of one of the mobile generators at its corporate office while others are used to reduce the impact of outages on customers.

The works contractor provides all generation required for network operations and outage mitigation, where required.

7.5.9.3 Voltage Regulation

Voltage is regulated at the zone substations using Automatic Voltage Regulator Relays (AVRRs) to control the power transformer tap changer. Several sites have been identified as having AVRRs which are no longer supported by suppliers and a risk upon failure.

7.5.9.4 Load Control Equipment

Fleet Overview

WELL 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 24 ripple injection plants on the network (one of which is a hot spare) and these are located at GXPs and zone substations. The Southern area has a 475Hz signal injected into the 33 kV network with one plant for each of the Wilton and Central Park GXPs and two plants injecting at the Kaiwharawhara 11 kV point of supply. The Northeast and Northwest areas have a 1050Hz signal injected at 11 kV at each zone substation.

An age profile of ripple plant is shown in Figure 7-35.

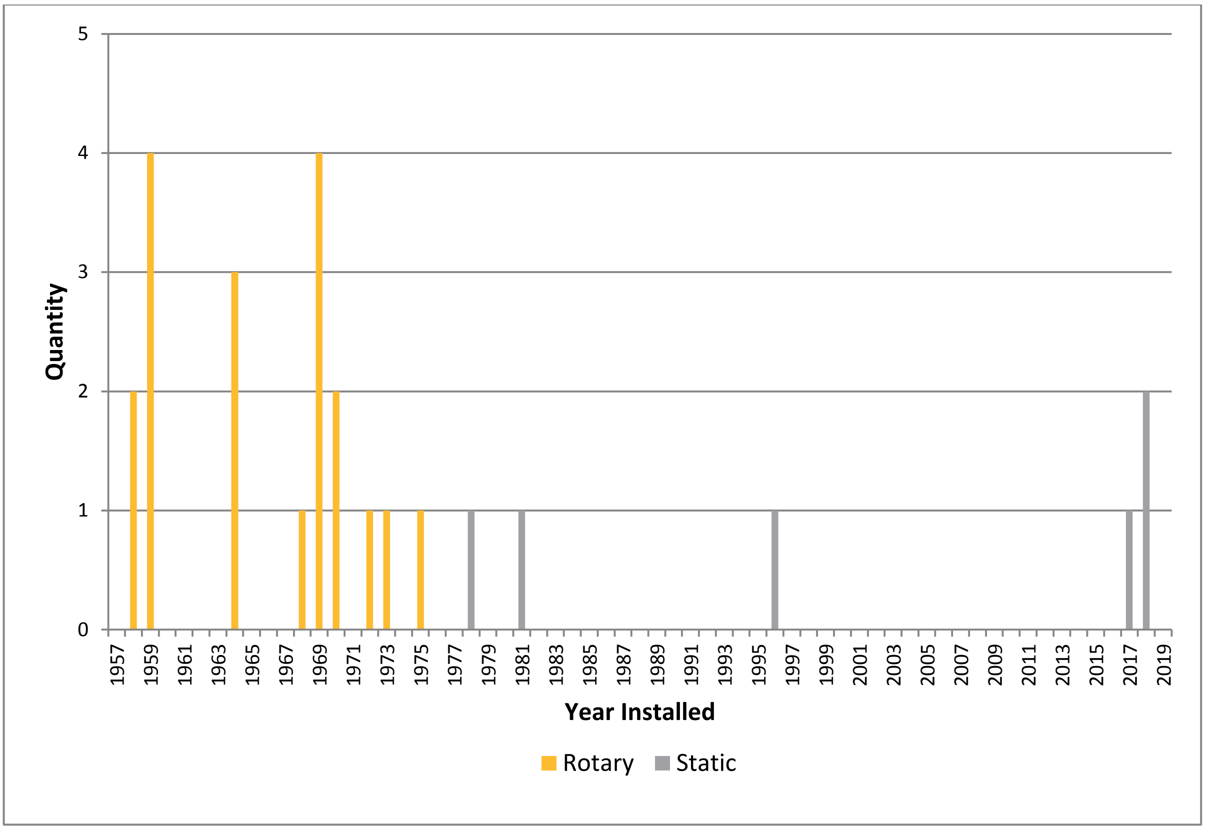


Figure 7-35 Age Profile of Ripple Plant

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on load control equipment. WELL owns the injection plants located at substations and the blocking cells at GXPs, but does not own the customer receivers. As such, the full end-to-end testing of the ripple system is problematic.

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

Table 7-65 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. WELL 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.

Primary Equipment

The rotary injection plants in the Hutt Valley area, while old, are easily maintained and repaired. Interconnectivity at 11 kV allows the ripple signal to be provided from adjacent substations in the event of failure.

The load on the plants has increased over the years and at some sites the coupling capacitors have been identified as a risk and are replaced with suitably sized units.

In February 2017, a static plant failed at Jubilee Road. This unit was replaced with the strategic spare and a replacement unit has since been installed.

Later in 2017, a static transmitter at Frederick Street failed which had to be replaced with the spare unit that had come out of Jubilee Road and a new strategic spare was purchased.

Load Control Master Station

The load control master station is at the end of its technical life and has been identified as a single point of failure risk. A replacement is currently being explored with the intention of carrying out the work once the complex nature of such a task has been entirely understood. This is further discussed in Section 10.

Load Control Programmable Logic Controller (PLC)

The load control PLCs are housed at the site of ripple injection and are responsible for coordinating the onsite operation of the ripple plant. These are at the end of their technical life and have been identified as being a risk of failing. A replacement programme is in development and will be coordinated after the zone RTU has been replaced.

Bus-Tie Auto Changeover Scheme

The bus-tie auto changeover scheme provides increased security for the Southern Area by utilising the N-1 capability in a timely fashion using an automatic scheme to isolate a subtransmission fault and close the bus-tie circuit breaker.

The scheme is only required in the Southern Area where the zone substation buses are split. A trial project will be carried out and then a programme developed for deployment at other eligible sites.

Strategic Spares

The spares held for load control plant is shown in Table 7-66.

Strategic Spares	
Injection plant	A spare 24kVA rotary motor-generator set is held for the 11 kV ripple system in the Hutt Valley. The spare 300kVA solid state transmitter at Frederick Street was used in 2017 during a breakdown. A new spare has been sourced and purchased. An assortment of coupling cell equipment is held in store.
Controllers	A spare Load Control PLC is kept as a strategic spare.

Table 7-66 Spares Held for Load Control Plant

Expenditure Summary for Other Network Assets

Table 7-67 details the expected expenditure other network assets by regulatory year.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Maidstone AVRR Replacement	123	-	-	-	-	-	-	-	-	-
Seaview AVRR Replacement	-	123	-	-	-	-	-	-	-	-
Kaiwharawhara LC PLC Replacement	-	60	-	-	-	-	-	-	-	-
Load Control PLC Replacement Programme	-	-	60	60	60	60	120	120	120	-
Reactive Capital Expenditure	200	200	400	400	400	400	400	400	400	400
AVRR Replacement Programme	-	123	123	123	123	123	-	-	-	-
Bus-Tie Auto changeover schemes	102	65	65	65	-	-	-	-	-	-
Capital Expenditure Total	**425**	**571**	**648**	**648**	**583**	**583**	**520**	**520**	**520**	**400**
Preventative Maintenance	70	68	68	68	68	68	68	68	68	68
Corrective Maintenance	1,139	1,109	1,015	1,006	1,012	985	985	985	985	985
Operational Expenditure Total	**1,209**	**1,177**	**1,083**	**1,074**	**1,080**	**1,053**	**1,053**	**1,053**	**1,053**	**1,053**

Table 7-67 Expenditure on Other Network Assets ($K in constant prices)

7.5.10 Assets Located at Bulk Electricity Supply Points Owned by Others

WELL owns a range of equipment installed at Transpower GXPs. These assets are included in the asset categories listed above, but are described further below.

7.5.10.1 33 kV and 11 kV Lines, Poles and Cables

WELL 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.

7.5.10.2 11 kV switchgear

WELL owns the 11 kV switchgear located within Kaiwharawhara GXP. The 11 kV switchboards at all other GXPs where supply is given at 11 kV are owned by Transpower.

7.5.10.3 Protection Relays and Metering

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

7.5.10.4 SCADA, RTUs and Communications Equipment

WELL owns SCADA RTUs and associated communications equipment at all GXPs.

7.5.10.5 DC Power Supplies and Battery Banks

WELL owns battery banks and DC supply equipment at all GXPs.

7.5.10.6 Load Control Equipment

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

7.6 Asset Replacement and Renewal Summary for 2020-2030

The total projected capital budget for asset replacement and renewal for 2020 to 2030 is presented in Table 7-68. This includes provisions 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	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Subtransmission	412	-	-	500	3,000	-	-	2,000	2,000	-
Zone Substations	550	1,450	2,400	200	200	200	200	200	200	200
Distribution Poles and Lines	7,452	7,185	7,437	7,265	7,006	6,924	7,007	6,865	6,494	6,446
Distribution Cables	761	870	875	881	889	1,895	1,902	3,409	3,416	3,423
Distribution Substations	5,332	3,797	3,731	4,065	4,336	4,825	4,825	4,825	4,825	4,825
Distribution Switchgear	4,714	4,256	4,413	4,373	5,208	5,346	5,350	5,359	5,355	5,352
Other Network Assets	2,579	2,063	2,742	2,884	2,987	2,831	2,821	2,727	2,655	2,477
Total	**21,800**	**19,621**	**21,598**	**20,168**	**23,626**	**22,021**	**22,105**	**25,385**	**24,945**	**22,273**

Table 7-68 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 Table 7-69. This budget is relatively constant, and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

Asset Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Subtransmission	85	85	85	85	85	85	85	85	85	85
Zone Substations	344	344	344	344	344	344	344	344	344	344
Distribution Poles and Lines	485	480	473	467	460	454	451	451	452	451
Distribution Cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations	515	515	515	515	515	515	515	515	515	515
Distribution Switchgear	757	758	759	760	761	762	762	763	764	765
Other Network Assets	257	255	255	255	255	255	255	255	255	255
Total	**2,443**	**2,437**	**2,431**	**2,426**	**2,420**	**2,415**	**2,412**	**2,413**	**2,415**	**2,415**

**Table 7-69 Preventative Maintenance by Asset Category
($K in constant prices)**

The forecast corrective maintenance expenditure by asset category is shown in Table 7-70. This excludes capitalised maintenance, which is instead incorporated into the Asset Renewal and Replacement expenditure forecast in Table 7-68. 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	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Subtransmission	200	200	200	150	150	150	150	150	150	150
Zone Substations	280	280	280	280	280	280	280	280	280	280
Distribution Poles and Lines	575	575	575	575	575	575	575	575	575	575
Distribution Cables	150	150	150	150	150	150	150	150	150	150
Distribution Substations	470	470	470	470	470	470	470	470	470	470
Distribution Switchgear	625	625	625	625	625	625	625	625	625	625
Other Network Assets	1,182	1,154	1,060	1,051	1,057	1,030	1,030	1,030	1,030	1,030
Total	**3,482**	**3,354**	**3,360**	**3,301**	**3,307**	**3,280**	**3,280**	**3,280**	**3,280**	**3,280**

**Table 7-70 Corrective Maintenance by Asset Category
($K in constant prices)**

7.6.1 Reliability, Safety and Environmental Programmes for 2020-2030

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 include the BAU seismic programme. The total projected capital budget for these categories is presented in Table 7-71.

Programme	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Feeder Reliability Projects	2,455	1,842	2,017	2,013	2,013	2,155	2,199	2,244	2,290	2,400
Extreme Event Mitigation	-	250	-	-	-	-	-	-	-	-
Total Quality of Supply	**2,455**	**2,092**	**2,017**	**2,013**	**2,013**	**2,155**	**2,199**	**2,244**	**2,290**	**2,400**
Seismic Programme[37]	1,167	700	300	650	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	**1,167**	**700**	**300**	**650**	**-**	**-**	**-**	**-**	**-**	**-**

Table 7-71 Reliability, Safety and Environmental Capital Expenditure
($K in constant prices)

7.6.2 Asset Management Expenditure

The total capital and operational expenditure forecasts are shown in Table 7-72 and Table 7-73. For clarity, these figures do not include the readiness seismic work, which is summarised in Section 11.5, and 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	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Asset Replacement & Renewal	21,800	19,621	21,598	20,168	23,626	22,021	22,105	25,385	24,945	23,223
Reliability, Safety & Environment	1,167	700	300	650	-	-	-	-	-	-
Quality of Supply	2,455	2,092	2,017	2,013	2,013	2,155	2,199	2,244	2,290	2,400
Subtotal - Capital Expenditure on Asset Replacement Safety and Quality	**25,422**	**22,413**	**23,915**	**22,831**	**25,639**	**24,176**	**24,304**	**27,629**	**27,235**	**25,623**

Table 7-72 Asset Management Capital Expenditure Forecast
($K in constant prices)

[37] Note that this expenditure does not include the Seismic Strengthening work covered by the SCPP which is specified in Section 11.

Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Service interruptions & emergency maintenance	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478
Vegetation management	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801
Routine & corrective maintenance and inspection maintenance	9,016	9,216	9,216	9,216	9,216	9,216	9,216	9,216	9,216	9,216
Asset replacement & renewal maintenance	958	958	958	958	958	958	958	958	958	958
Subtotal - Operational Expenditure on Asset Management	**16,254**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**

Table 7-73 Network Operational Expenditure Forecast ($K in constant prices)

Section 8

System Growth and Reinforcement

8 System Growth and Reinforcement

This section sets out WELL's network development 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 Sections 5 and 6.

Due to the uncertainty in how demand for network capacity will change over time, planning for development investment requires ongoing 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 expect.

During 2019, a significant review was completed of future growth capital requirements in light of recent regional ICP growth levels. As a result of the review, new significant projects have been included in the AMP forecast including the Porirua zone substation rebuild and the construction of a new substation at Grenada to increase capacity in the surrounding areas.

Network reinforcement planning is also considered in conjunction with the development requirements from condition based and resiliency based projects. The penetration of emerging technologies may have large impact on the LV reticulation however the actual impact on HV network is yet to be identified due to its large degree of uncertainty. Under the current regulatory DPP allowance model there may not be sufficient funding to cover additional expenditure for WELL to fully implement network development projects that deliver a higher level of system security, infrastructure resiliency or the investment requirements for supply quality or capacity upgrade due to emerging technology penetration.

This section covers:

- Network planning policies and standards;
- Demand forecasting;
- System growth capex for primary assets;
- System growth capex for secondary assets; and
- System growth expenditure summary.

8.1 Network Planning Policies and Standards

The purpose of these policies and standards is to ensure the network delivers the service levels and network performance discussed in Sections 5 and 6.

The policy and standards cover the following areas:

- Security criteria – which specifies 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;
- 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 following sections.

8.1.1 Security Criteria

The design of WELL's network is based on the security criteria shown in Table 8-1 (subtransmission criteria) and Table 8-2 (distribution criteria).

The security criteria are consistent with industry practice[38] 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 and reduce system losses.

The security criteria accept there is a small risk that supply may be interrupted, and cannot be backfed, if a fault occurs during peak demand times. This is a balance of risk and cost and is considered a prudent approach rather than removing the small risk altogether.

The WELL subtransmission network consists of a series of radial circuits from Transpower's GXPs to the zone substations. The zone substations do not have a 33 kV bus and the subtransmission circuits connect directly onto the high voltage terminals of the 33/11 kV power transformers. In the Southern Area the 11 kV bus is normally operated open to restrict fault levels. Within the Northwestern and Northeastern areas the 11 kV 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 11 kV bus is normally operated open,

[38] *Guide for Security of Supply*, Electricity Engineers' Association, August 2013.

there will be a brief interruption to consumers following a subtransmission or transformer fault, while the bus tie is closed. This is considered to satisfy the N-1 security criteria. There is currently a programme underway to implement an automatic bus tie change-over scheme to improve reliability without needing to operate the system at higher prospective fault levels.

Subtransmission

The length of time (defined as a percentage) when the subtransmission network cannot meet N-1 security is defined for each category of consumer. Limits are also set on the maximum load that would be lost for the occurrence of a contingency event. The security criteria are based on the sustained peak demand which is calculated as 'loading that lasts for two hours or longer 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.

Table 8-1 shows the applicable security criteria for the subtransmission network.

Type of Load	Security Criteria
CBD	N-1 capacity[39], 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.

Table 8-1 Security Criteria for the Subtransmission Network

Distribution

Table 8-2 shows the applicable security criteria for the distribution network.

Type of Load	Security Criteria
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 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 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.

[39] A brief supply interruption of up to five minutes may occur following an equipment failure while the network is reconfigured.

Type of Load	Security Criteria
HV direct / LV Supply to customer	Loss of supply upon failure unless customer specified a higher security requirements. Supply restoration dependent on repair time.

Table 8-2 Security Criteria for the Distribution Network

Basis for the criteria

While the reliability of WELL's HV distribution system is high, notwithstanding the difficult physical environment in which the system must operate[40], 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 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 consumers, 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. WELL has emergency plans in place to prioritise response and repair efforts to assist mitigating the impact of such situations (as discussed in Section 11) but, when they occur, longer supply interruptions than shown in the tables are possible.

Most of the 11 kV feeders in the Wellington CBD, in some locations around Wellington city 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 11 kV network outside these areas typically comprises radial feeders with a number of mid-feeder switchboards with circuit breakers.

Most of the radial feeders are connected through normally open interconnectors to other feeders so that, in the event of an equipment failure, supply to consumers 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 WELL operates the distribution feeders during normal and contingency operation is identified in Table 8-3. 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.

[40] Much of WELL'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.

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 or Radial section of Mesh Ring	66	100

Table 8-3 11 kV 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, WELL offers a range of alternatives that provides different levels of security at different costs (price/quality trade off). The consumer can then choose to pay for a higher level of security to meet their needs for the load that are being supplied.

8.1.2 Voltage Levels

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

Regulation 28 of the Electricity (Safety) Regulations 2010 requires that standard LV supply voltages (230V single phase or 400 V 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 WELL zone substation transformers are fitted with on-load tap changers (OLTC) controlled by voltage regulation systems 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. Future DER devices will be required to implement suitable power quality response modes to meet supply quality requirements.

8.1.3 Fault Levels

WELL operates its 11 kV network to restrict the maximum fault level to 13 kA 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 11 kV 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 13 kA (except Korokoro which exceeds 13 kA but has acceptable downstream fault rated switchgear), meaning the 11 kV bus can be operated closed, with the supply transformers supplying a common bus. New switchgear is typically rated for 25 kA for use within zone substations and 21 kA for use within the distribution network.

8.1.4 Power Factor

All connected consumers are responsible for ensuring that their demand for reactive power does not exceed the maximum level allowed, or the power factor limits specified in WELL's network pricing schedule and connection requirements. The power factor of a consumer's load measured at the metering point must not be lower than 0.95 lagging at all times. Corrective action may be requested by WELL if the consumer's power factor falls below this threshold.

8.1.5 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. Harmonic distortion levels are defined by 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 consumer.

8.1.6 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 as well as designs for underground subdivisions.

There is no standardisation of high voltage (HV) network augmentation because these are project by project dependent.

8.1.7 Energy Efficiency

The processes and strategies used by WELL that promote the energy efficiency of the network are:

- Network planning – to design systems that do not lead to high losses or inefficient distribution 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).

8.1.8 Non-Network Solution Policy

Non-network solutions include load control, demand side management solutions, use of emerging technologies and network reconfigurations.

WELL'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 also resulted in providing an effective means of promptly returning supply to consumers following network outages.

WELL specifies equipment for use that incorporates new technologies where it is practicable and economic to do so. This means that new technologies will be implemented if the benefits to the network and stakeholders meet or exceed the additional costs incurred in procuring, 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.

There is also a great level of uncertainty with the fast changing nature of the emerging technologies. WELL's approach is described in Section 9. To date the cost of implementing emerging technologies have been found to be significantly higher than the alternative network-based solutions. WELL will continue with the development of a future pricing roadmap to keep the network efficient and enable the introduction of new technology with minimal network impact.

The options available typically 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. WELL currently monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets. Where there is risk of exceeding the thermal overload limits due to equipment failure or constraints, 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.

8.1.9 Impact of Distributed Generation

The magnitude of small distributed generation currently installed within the network is relatively low[41] compared to other areas in New Zealand and overseas, and is expected to remain relatively low across the first half of the planning period. This assumption will be monitored and re-assessed in the event of large

[41] Installed capacity, excluding standby generation and Mill Creek (connected at 33 kV), is only 15.8MVA, or 0.3% of the system demand.

scale uptake of distributed generation in the future and annually in the AMP process. WELL welcomes enquiries from third parties interested in installing embedded generation and has a well-defined connection policy, as described below.

8.1.9.1 Connection Policy

WELL 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.

The AS 4777 "Grid Connection of Energy Systems Via Inverters" referred to in the code has been recently updated and is currently before Energy Safety for approval. Adoption of the new AS/NZS 4777 standard through code amendment is currently under consultation. It is expected to be accepted into the regulations and code in 2020, following which WELL will update its standards. As part of the WELL DG / DER connection standard development, WELL will also consider using the EEA "Guideline for the Connection of Small-Scale Inverter Based Distributed Generation" and other relevant industry guides.

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);
- 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 WELL and its consumers.

Information about connecting distributed generation is available on the WELL website – www.welectricity.co.nz or by calling 0800 248 148.

8.1.10 Asset Capacity Definition

Primary assets in WELL network are classified into the following hierarchy of categories with planning criteria and operational requirements for the different assets shown in Table 8-4.

Primary Asset Categories	Asset Boundary	Security Planning Criteria
Tier 0 – Upstream Asset	GXP Feeder CB Cable Termination and above	National Grid Planning Criteria
Tier 1 – Subtransmission	From GXP CB Cable Termination to ZS 11 kV Bus before Feeder CB	Subtransmission Security Criteria, Maximum Continuous Branch Rating (MCBR)
Tier 2 – HV Feeder Distribution	From ZS Feeder CB to Distribution Substation HV Distribution Substation Ring Switch before teed connection to HV Load switch	Distribution Security Criteria, Maximum Continuous Branch Rating (MCBR)
Tier 3 – HV Distribution Substation	From Distribution Substation load switch to LV Bus	Distribution Security Criteria, Cyclic Rating
Tier 4 – LV Feeders	From LV Feeder switch to customer demarcation point	Distribution Security Criteria, Peak demand and ADMD demand, Cyclic Rating
Tier 5 – Customer Assets (HV direct or LV)	From network demarcation point	Peak demand and ADMD demand, Customer provided equipment rating

Table 8-4 Security Criteria for the Distribution Network

In general, for 11 kV and 33 kV network planning purposes, the continuous ratings are used, whereas the cyclic ratings are used for planned operational activities and the emergence overload ratings are for unplanned contingency events.

Asset capacity is further defined as follows:

- Power transformers – The transformer ratings include the continuous asset capacity (based on a continuous uniform load profile), the cyclic capacity and a short duration (2 hour) emergency overload rating (dependent on the maximum operating temperature of the transformer);
- 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;
- Maximum Continuous Branch Rating (MCBR) – This is determined based on the lowest rated component of the circuit, i.e. a transformer may be rated to 36MVA while the supplying cable is only capable of 21MVA and 17MVA during winter and summer respectively. Thus the effective MCBR is limited to the seasonal rating of the cable;
- HV 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; and

- LV distribution transformers and circuits – This section does not include analysis on distribution transformers or LV circuits, which have been traditionally managed in a reactive approach. Asset capacity in this category is largely driven by the usage pattern and demand response from individual customers. Section 9 outlines the development plans and trial projects that have direct interface with LV connections.

The capacity of all HV network elements is modelled in the DigSILENT PowerFactory network model with a seasonal scaling factor applied, providing a tool to analyse network integrity against the security standard.

8.2 Demand Forecast 2020 to 2030

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 WELL'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. 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 WELL load is traditionally winter peaking, recent trends have shown that a few of the zone substations within the Wellington City are now summer peaking.

8.2.1 Demand Forecast Methodology

The forecasting methodology utilised by WELL is based on a building block approach, from 11 kV 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 30 September to 1 October in the following year;

2. The average growth rate over the last five years is utilised to establish the 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. 12 scenarios from permutations of the three growth scenarios (high, historical, low) and the four seasonal temperature variations (Summer, Mild Winter, Average Winter and Cold Winter) are used for sensitivity analysis; and

4. The addition of known future step change demand at specific sites. The EV/PV penetration is still low and does not yet have a significant step change impact on the peak demand.

The growth scenarios are aggregated 'bottom-up' from feeder level to provide GXP, region and system wide forecasts allowing for diversity at each level. An overview of the demand forecast methodology is shown in Figure 8-1.

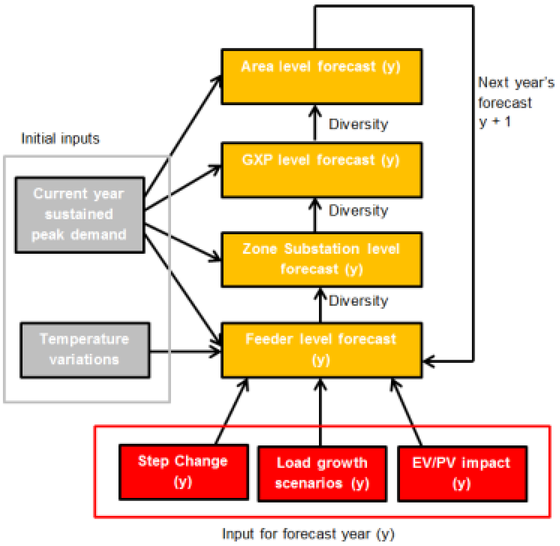


Figure 8-1 Demand Forecasting Methodology

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 is 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.

8.2.1.1 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[42];
- No allowance is made for any significant demand changes due to major weather events or unforeseen network condition causing significant outages or abnormal operation of the network;
- No significant impact is assumed from disruptive technologies such as PV or distributed generation, as discussed in Section 9; and
- 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.

[42] Total amount of controllable load on average is about 9% of the peak demand, but expected to slowly decline.

In order to calculate the sustained peak demand, forecast is based on the following information and apply assumptions listed earlier in this section:

- 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[43] 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 Statistics New Zealand[44] 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.

8.2.2 Temperature Variation

Network demand shows a strong correlation with the ambient temperature. 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.

The short-term demand variation in summer does not show a strong correlation with temperature variation, but the overall relationship of high temperature and low summer demand is observed. Therefore, 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 8-2, 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.

[43] Diversity factors represent the difference in times of peak demand between different sites.

[44] NZ Statistics Subnational Population Projections: 2006 (base) – 2043 (October 2016 update). Used for 10+ year forecasting.

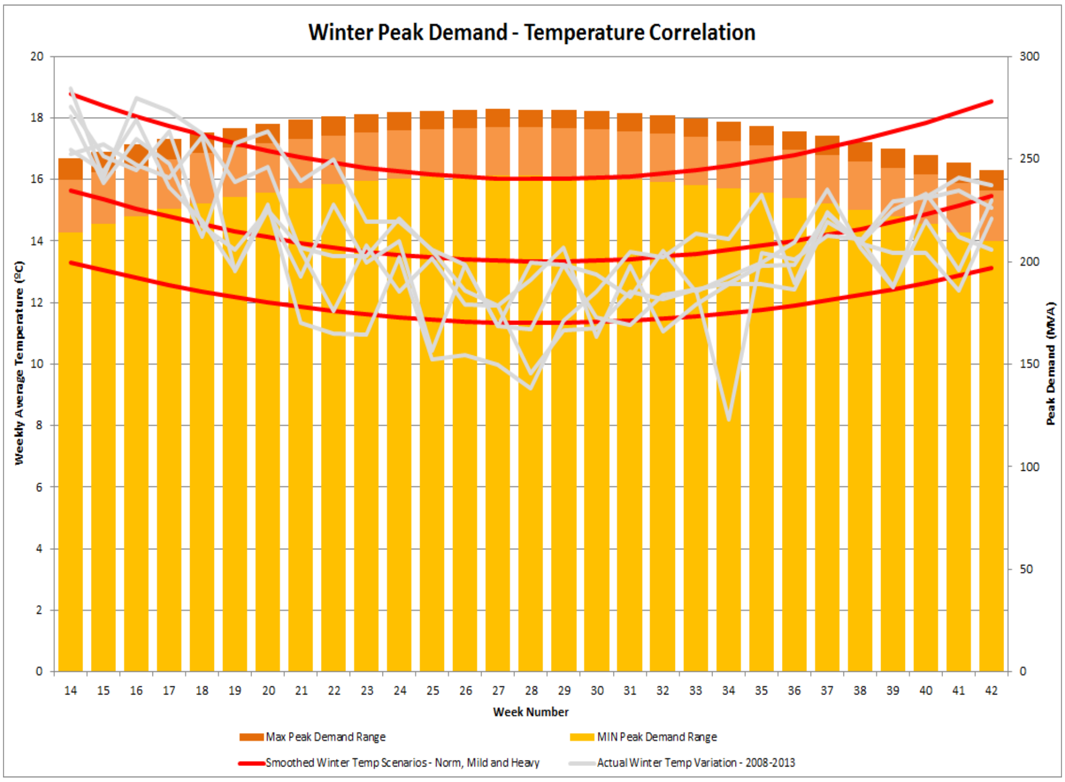


Figure 8-2 Temperature Volatility Correlation to Peak Demand Range

For example, for week 31 as shown in Figure 8-2, 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.

Figure 8-3 shows an example of the correlation between temperature and maximum demand.

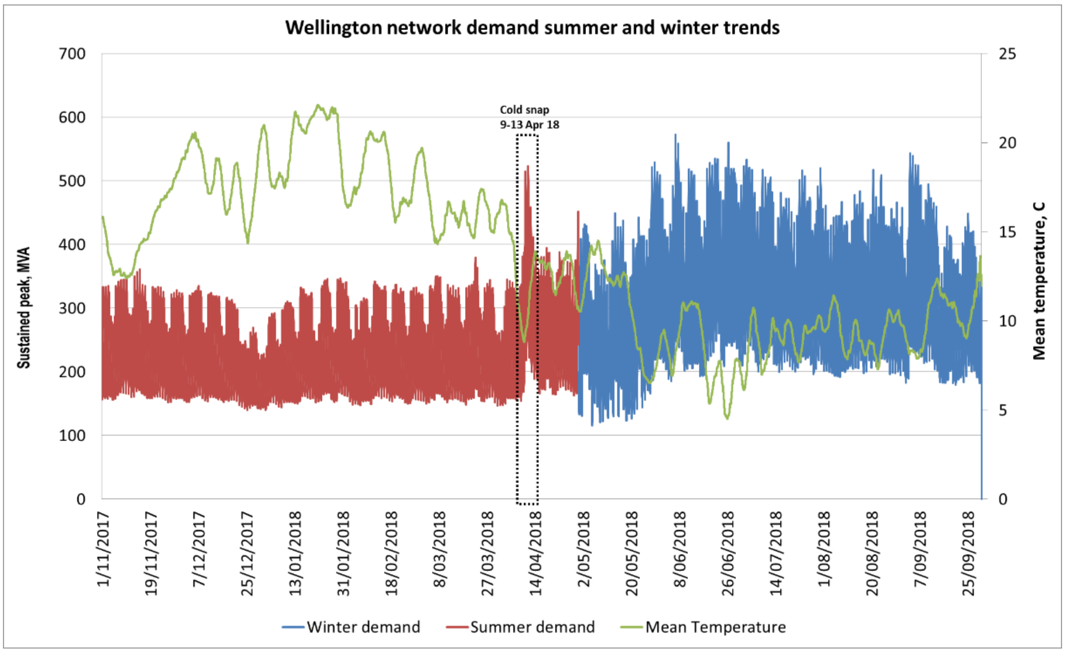


Figure 8-3 Wellington Network Summer and Winter Demand Variation

8.2.3 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 with a total connection capacity above 450 kVA or ADMD capacity above 200 kVA;
- 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, likely developments detailed in the individual local council District Plans and consultation with City Councils, developers, and large consumers. 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. The actual outcome from step change demands is uncertain, and difficult to estimate more than 12 to 24 months in advance.

8.2.4 Demand Change Due to DER Penetration

New technologies such as DER devices, as discussed in Chapter 9, will likely impact network load patterns and the overall system demand forecast. In 2019, further studies on DER penetration, specifically around EV load and the counter balance of other DER devices, have been carried out to assess its potential impact. The impact assumption is based on penetration forecast, location, change of EV charger output and its diversity, as well as the effectiveness of a demand response program.

The study has indicated that, based on today's best knowledge, even with an effective demand response program in place, asset reinforcement will still be required at some locations in the next 8 to 10 years. Figure 8-4 shows a zone substation load forecast with and without DER penetration.

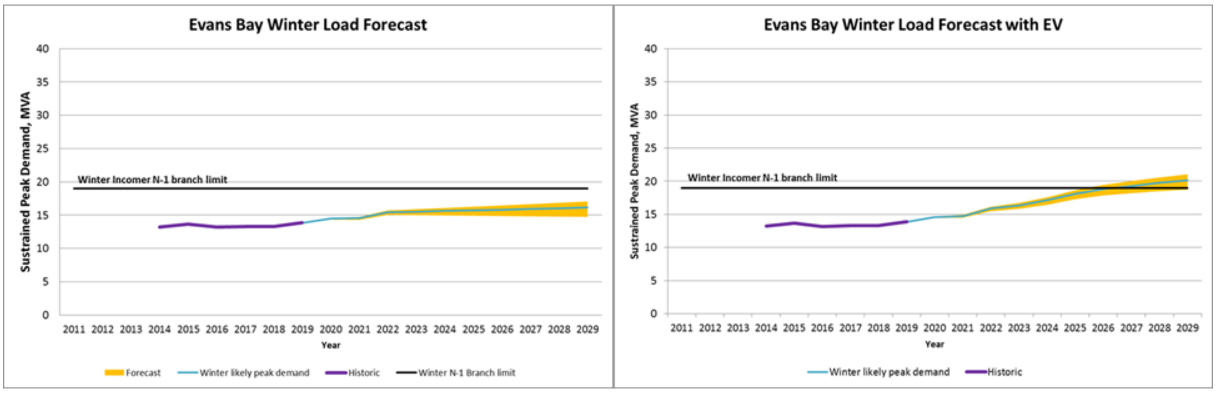


Figure 8-4 Forecast Impact of DER on Load Growth for a Typical Zone Substation

However, there remains significant uncertainty, including degree of counter balance between impact of DER devices, policy change, price signal change and technology change. On this basis, the load forecast in this section has not included results from the DER penetration study. The impact of DER will continue to be analysed over the 2020 year with further demand forecast updates provided in the future.

8.2.5 Typical Load Profiles

Typical annual demand profiles for the CBD and residential loads are shown in Figure 8-5 and Figure 8-6. 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.

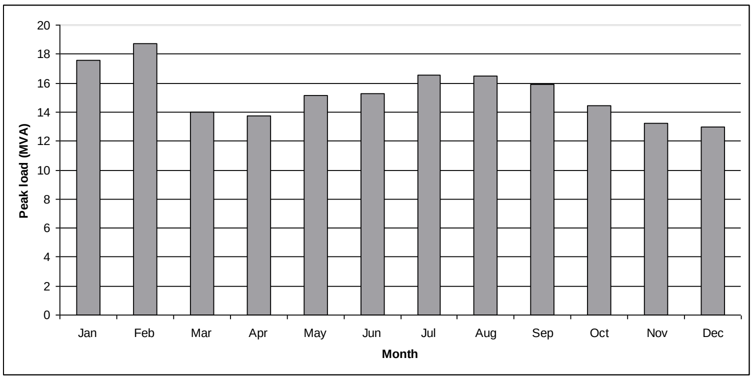


Figure 8-5 Typical CBD Monthly Peak Load Profile

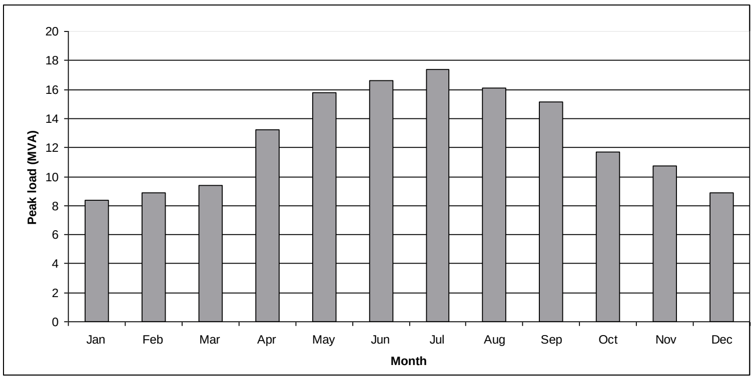


Figure 8-6 Typical Residential Monthly Peak Load Profile

Typical daily demand profiles are shown in Figure 8-7 and Figure 8-8. 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. These profiles are subject to change as the uptake of electric vehicles and demand management technologies changes over time.

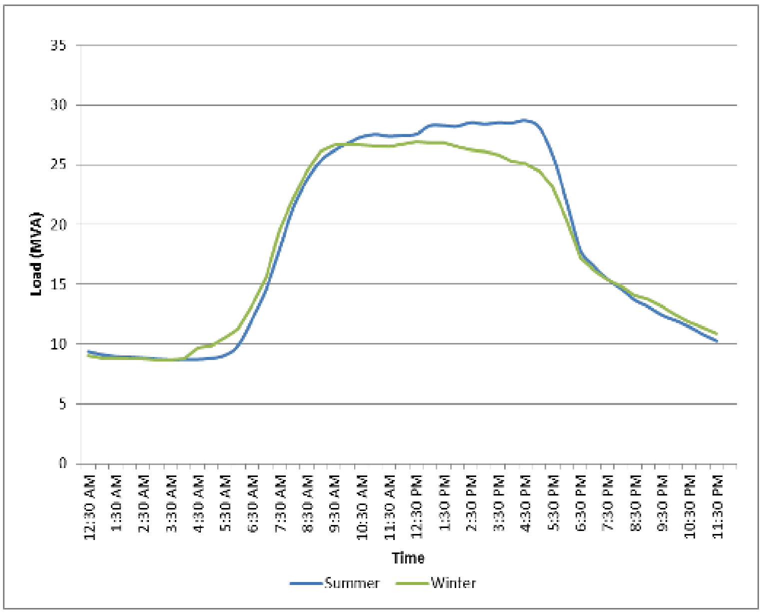


Figure 8-7 Typical CBD Zone Substation Daily Load Profile

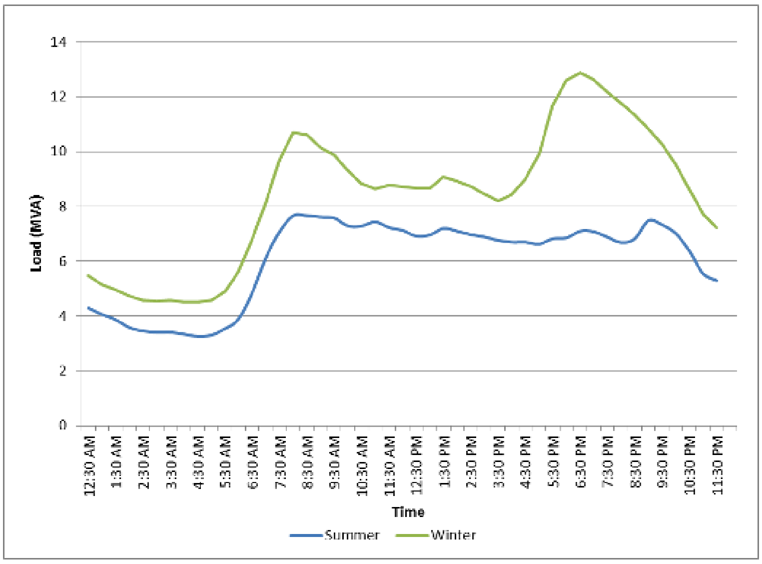


Figure 8-8 Typical Residential Zone Substation Daily Load Profile

8.2.6 Wellington Regional Peak Demand Forecast

The system peak demand forecast to 2029 is shown in Table 8-5. These figures assume an average winter. In practice the actual maximum demand will be influenced by whether the winter is milder or colder than average. For example, winter 2019 was milder than average, resulting in a network peak demand less than forecast for an average winter.

Network	Peak Demand (MVA)										
	2019 Actual	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Maximum Demand (MVA)	550	563	564	566	567	568	570	571	573	575	576

Table 8-5 Forecast Network Peak Demand

The contribution of each GXP and DG to the 2019 winter peak is detailed in Table 8-6.

Location	2019 Coincident Peak Demand (MVA) – 31 July 2019 Block 37														
	Central Park	Gracefield	Haywards	Kaiwharawhara	Melling	Pauatahanui	Takapu Road	Upper Hutt	Wilton	Mill Creek	Wellington Wind	Silverstream	Southern Landfill	Other Small DG	Total
Coincident Peak Demand (MVA)	167	61	34	27	64	20	94	32	-8	55	1	2	0.9	1	**550**

Table 8-6 2019 Coincident Peak Demand

The peak network demand is expected to grow at a rate of 0.0 – 0.9% p.a. over the next five years. This is driven by planned step change loads such as:

- Planned residential developments in the Porirua Northern Growth Area, Churton Park, Aotea, Whitby, Grenada North and Upper Hutt areas; and
- Expansion plans of a number of commercial and industrial consumers.

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, better insulation and consumer side demand monitoring typically result in a reduction in demand for an existing connection point;
- Uptake of new technologies such as EVs, residential and commercial batteries, and residential PV generation and gas connections;
- Observed diversity in peak load coincidence leading to a long term reduction of overall peak demand; and
- Consumer response to pricing signals and policy changes.

8.2.7 Network Area Step Change Development

This section provides a high level summary of known local step change development in each network area.

8.2.7.1 Southern - Step Change Developments

Peak demand in the Southern Area has been flat or in decline 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. However, the impact of the November 2016 earthquake has introduced uncertainty into the regional forecast.

Energy consumption within the Southern Area network has also been flat due to a general trend towards energy efficiency.

Expected developments in the Southern Area include:

- Approved customer connection requests for a new government and ministerial buildings along Molesworth Street;
- High density residential and commercial developments in the Cuba and East Te Aro precincts, including the new Conference Centre;
- Residential subdivision of Erskine College;
- Wellington Bus Operators that intend to introduce electric bus fleet requiring potentially up to 5 MVA from Evans Bay, Island Bay and Thorndon; and
- Wellington Children's Hospital and other hospitals that have requested capacity increase giving a total demand of approximately 2.25 MVA.

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.

8.2.7.2 Northwestern - Step Change Developments

The Northwestern Area is continuing to grow organically with the strongest level of residential development within WELL's network. There is relatively high interest for new residential subdivisions in the suburbs of Kenepuru, Whitby, Grenada North and Churton Park. The Aotea subdivision, currently supplied from the Porirua and Waitangirua zone substations, is still an area of growth.

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, Churton Park and Grenada area, particularly around the Johnsonville town centre within the next 3 years;
- Residential development in Whitby is expected to contribute 700 kVA peak demand within the next 10 years;
- Residential and commercial development in the Aotea Block development area is expected to contribute 3.15 MVA within the next 10 years. Residential development is currently in progress at a rate of 100 lots or 150 kVA of additional peak demand per year. Commercial development in the Aotea

Block business park is expected to provide a further 300 kVA per year in the last five years of development;

- The growth areas, identified by the Porirua City Council, north of Plimmerton (Northern Growth Area) and in the Pauatahanui-Judgeford areas. Development of these is expected to coincide with completion of the NZTA Transmission Gully project in 2020. Allowing for the expected growth of approximately 2.5 MVA of growth is estimated prior to the end of the planning period. Growth is expected at a rate of 150-300 kVA of peak demand per year for the last five years of the planning period;

- Housing New Zealand plans to build an addition 2,000 units over the next 20 years in Eastern Porirua is expected to contribute an average of 300 kVA to the peak demand annually;

- Kenepuru landings residential, retirement village and light commercial development adding up to 5 MVA over the next five years; 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 1.5 - 2.3 MVA.

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.

There is limited capacity and HV supply coverage around the existing network boundaries, particularly in the Titahi Bay, Plimmerton and Pauatahanui areas. WELL will work closely with customers on network expansion requirements for new connections and capacity upgrade projects.

8.2.7.3 Northeastern - Step Change Developments

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 consumers in the Trentham and Maidstone zone substation supply areas.

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 the 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 an additional two confirmed stages for a total increase in installed capacity of approximately 2 MVA over the next two years. New infrastructure is planned to provide the required capacity and security of supply to these facilities, while also providing increased inter-connectivity within the network;

- Expansion of industrial loads in the Gracefield and Seaview areas adding approximately 2 MVA demand;

- Redevelopment of an existing industrial premise to house the new Ministry of Primary Industries research centre. A load increase of 1.5 MVA is expected within the next two years;

- A new residential development in the Wallaceville area comprising 700 lots that will release 100 sections with an installed capacity of 300 kVA per year for four years, with an expected maximum demand of 1.2 MVA; and
- CBD revitalisation will likely add about 1 MVA over the next 10 years. In addition, possible major commercial developments in the Maidstone area may add approximately 5 MVA, but are still at the exploratory stage and therefore not yet included in the load forecast.

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.

There is limited capacity and HV supply coverage around the existing network boundaries, particularly in the Upper Hutt area and Wainuiomata area. WELL will work closely with customers on network expansion requirements for new connections and capacity upgrade projects.

8.2.8 GXP and Zone Level Demand Forecasts

The following tables show the GXP and zone substation level forecast for each area within the Wellington network. Table 8-7 shows the GXP level forecast by area and Table 8-8 shows the zone substation level forecast by area. For both tables, the base maximum demand value for the forecast is for the last 12 months and area totals are coincident sustained peak demand values.

Area	GXP[45]	Actual and Forecast Sustained Peak Demand[46] (MVA)										
		2019 Actual	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Southern	Central Park 33 kV	133	136	139	140	141	143	144	145	147	148	150
	Central Park 11 kV	21	22	23	25	25	25	25	25	25	25	25
	Wilton 33 kV	36	42	44	45	46	47	47	47	48	48	48
	Kaiwharawhara 11 kV	28	30	32	34	30	30	30	30	31	31	31
Northwestern	Pauatahanui 33 kV	17	18	18	19	19	20	20	22	22	27	27
	Takapu Rd 33 kV	89	91	95	98	105	108	111	114	117	116	118
Northeastern	Gracefield 33 kV	53	55	55	56	57	58	58	59	59	60	61
	Haywards 33 kV	15	14	15	15	15	16	16	16	16	16	16
	Melling 33 kV	30	29	28	29	29	29	29	29	29	29	29
	Upper Hutt 33 kV	28	26	27	27	27	28	28	28	28	28	28
	Haywards 11 kV	16	16	16	16	16	16	16	16	17	17	17
	Melling 11 kV	23	24	28	28	28	28	28	29	29	29	29

Table 8-7 Wellington Area GXP Level Forecast

[45] Transpower's published P90 forecasts at the GXP level allow for a large margin of uncertainty, prudent for transmission level planning and as such, are not consistent with WELL's forecasts which are less conservative for the purposes of subtransmission and distribution planning.

[46] 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[47] (MVA)										
		2019 Actual	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Southern	8 Ira Street	15	16	16	17	17	17	17	18	18	18	18
	Evans Bay	14	14	14	15	15	16	16	16	16	16	16
	Frederick Street	27	29	30	30	30	30	31	31	31	31	31
	Hataitai	15	15	16	16	16	17	17	17	17	18	18
	Palm Grove	24	25	26	24	25	25	25	25	26	26	26
	Terrace	29	30	30	30	31	31	31	31	32	32	32
	University	18	19	19	19	19	19	19	19	19	19	19
	Nairn Street	21	22	23	25	25	25	25	25	25	25	25
	Karori	15	15	15	16	16	16	17	17	17	18	18
	Moore Street	23	24	26	27	27	27	28	28	28	28	28
	Waikowhai Street	14	14	14	14	14	14	14	14	14	14	14
Northwestern	Mana	9	9	9	9	9	9	9	10	10	14	14
	Plimmerton	8	9	9	10	10	11	11	12	12	13	13
	Johnsonville	19	20	21	21	22	23	24	25	25	26	26
	Kenepuru	11	12	16	17	17	18	18	19	19	19	19
	Ngauranga	10	12	12	12	16	17	17	17	17	17	17
	Porirua	20	22	21	21	22	22	23	23	24	21	21
	Tawa	14	15	16	17	17	18	19	20	21	21	22
	Waitangirua	14	14	14	15	15	15	16	16	17	17	18
Northeastern	Gracefield	9	12	12	12	12	12	12	12	12	12	12
	Korokoro	18	18	15	15	15	15	15	15	16	16	16
	Seaview	17	16	19	19	19	19	19	19	19	20	20
	Wainuiomata	17	17	18	19	19	20	20	21	21	22	22
	Trentham	14	15	15	15	15	16	16	16	16	17	17
	Naenae	15	16	16	16	16	16	16	16	15	15	15
	Waterloo	17	16	16	16	16	16	16	16	16	16	16

[47] 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[47] (MVA)										
		2019 Actual	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	Brown Owl	15	14	14	15	15	15	15	15	15	15	15
	Maidstone	15	15	15	16	16	16	16	16	16	16	16

Table 8-8 Wellington Area Zone Substation Level Forecast

8.3 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 however planning for each network area uses a consistent methodology.

The discussion for each area is structured in accordance with the network hierarchy of GXP level requirements, subtransmission and zone substations and then distribution level investments. The GXP level discussion has been developed with reference to Transpower's Transmission Planning Report (TPR) and other formal discussions with Transpower regarding their proposed development plans.

The NDRP for each network area is described in the following respective sections. Each section provides a summary of the NDRP and is structured as follows:

- Potential GXP developments;
- Identified subtransmission development needs;
- Identified HV distribution network development needs; and
- A summary of network development plan and expected expenditure profile.

Options for resolving each subtransmission development need are summarised in Appendix D.

8.4 Southern Area NDRP

This section provides a summary of the Southern Area NDRP.

8.4.1 GXP Development Plans

The Southern network is supplied from four GXP points at three locations, Central Park, Wilton and Kaiwharawhara. The transformer capacity and the maximum system demand are set out in Table 8-9.

GXP	Continuous Capacity (MVA)	Cyclic Summer / Winter Capacity (MVA)	Maximum Sustained Demand (MVA)	
			2019	2029
Central Park 33 kV	2x100 1x120	2x 108 / 112	133	150
Central Park 11 kV	2x25	29 / 30	21	25
Wilton 33 kV	2x100	103 / 110	36[48]	48[48]
Kaiwharawhara 11 kV	2x30	38 / 38	28	31
Total (after diversity)	-	-	**218**	**254**

Table 8-9 Southern Area GXP Capacities

The development need at each GXP is discussed below.

8.4.1.1 Central Park GXP

The Central Park GXP consists of a sectionalised 33 kV bus and 14 subtransmission feeders to seven zone substations, two 33/11 kV transformers and an 11 kV bus. Each zone substation is supplied from two separate bus sections to provide N-1 redundancy. The 11 kV bus at Central Park supplies Nairn Street zone substation.

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Transmission Planning Report. In 2019, WELL formally requested Transpower to carry out a resiliency and development option review at Central Park GXP and is currently in discussions with Transpower on various shortlisted options, including location selection and geotechnical studies. In 2020 the key focus will be finalising the design options so a preferred development plan can be presented to stakeholders in a consultation process to seek their approval. The timeline to complete this resiliency project is around 2024/25.

8.4.1.2 Wilton GXP

Part of the Wellington CBD is supplied from the Wilton 110 kV bus which has been identified as a risk and Transpower has recently completed a project to rebuild it as a three-section bus. This addresses the supply

[48] Wilton 33 kV ADMD sustained peak demand excluding West Wind generation.

diversity and resilience concerns at Wilton as each of the three Central Park circuits are now 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 220 kV or 110 kV 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.

In 2019 after a major fault on the Wilton 33 kV bus Transpower initiated an improvement project to resolve the design issue at Wilton and other locations where the similar issue was identified.

Based on the demand forecasts, the loading will not breach the firm capacity at Wilton during the planning period.

8.4.1.3 Kaiwharawhara GXP

Transpower has no planned works at Kaiwharawhara and based on the demand forecasts, the loading will exceed the firm capacity for a few years and this will be managed operationally. WELL has built a project plan for peak reduction at Kaiwharawhara. This work plan will be delivered in conjunction with customer capacity increase projects within the planning period.

Figure 8-9 shows the load duration curve against the subtransmission N-1 ratings.

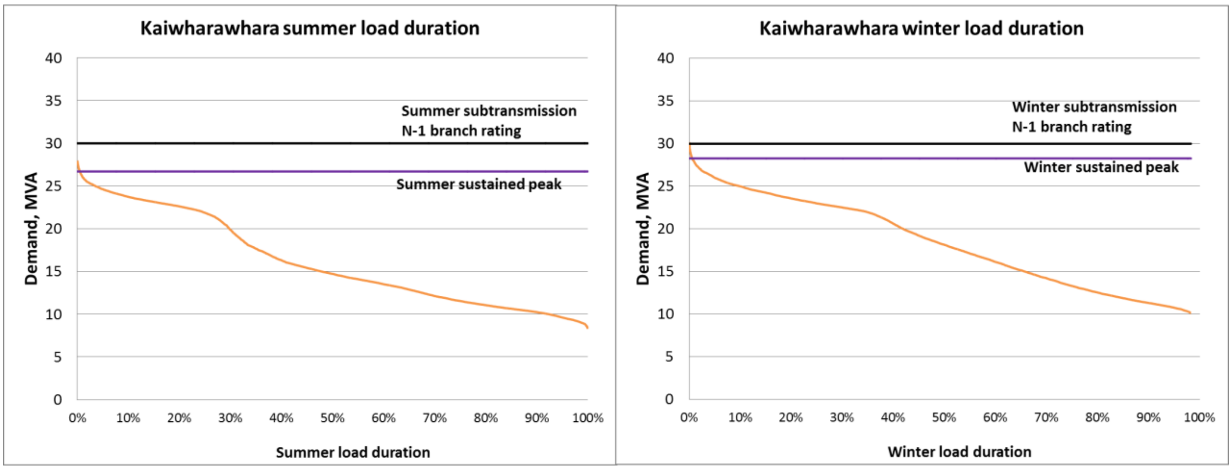


Figure 8-9 Kaiwharawhara Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Kaiwharawhara is forecasted to change as shown in Figure 8-10. The subtransmission capacity constraints are plotted for comparison. Without action, the summer load growth is forecast to breach the subtransmission N-1 capacity from 2021.

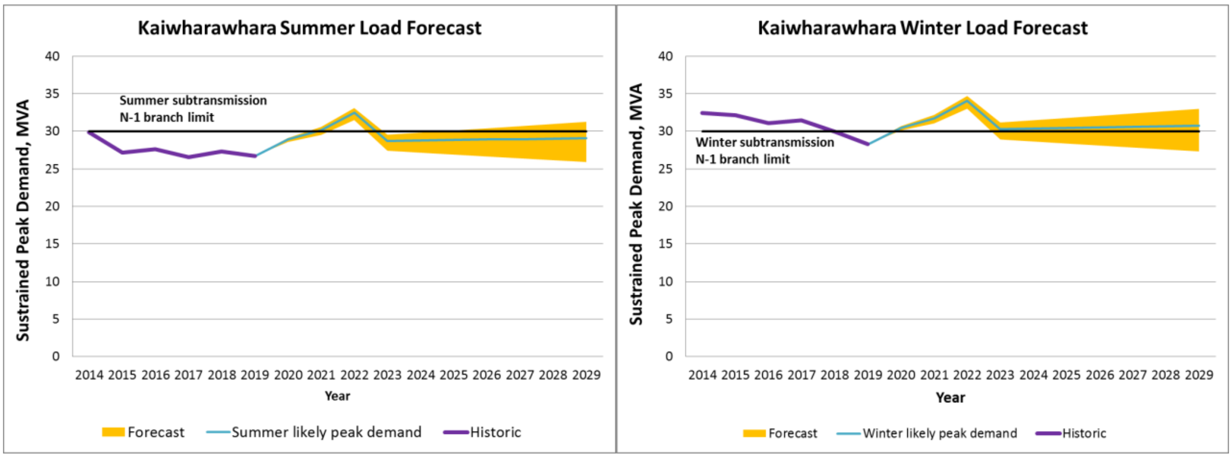


Figure 8-10 Kaiwharawhara Load Forecast

8.4.2 Subtransmission Network Development Needs

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 33 kV circuits supplying 11 zone substations. Each zone substation supplies the respective 11 kV distribution network with inter-connectivity via switched open points to adjacent zones. A supply capacity and demand overview of each zone substation is listed in Table 8-10. Assets causing capacity constraints are shown in red text in the table.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch Component[49]	Sustained Peak Demand (MVA)		Date Constraints are Binding	ICP Counts as at 2019
				2019	2029		
Existing constraints							
Frederick Street	Winter	23.2	33kV cable	27.4	31.0	Existing	7,275
	Summer	19.5	33kV cable	21.5	24.0		
Palm Grove	Winter	24	33/11kV transformer	24.2	26.0	Existing	10,432
	Summer	24	33/11kV transformer	17.5	18.5		
Forecasted constraints							
The Terrace	Winter	30	33/11kV transformer	27.1	31.0	2021	1,621
	Summer	30	33/11kV transformer	29.2	32.1		

[49] Subtransmission branch consists of incoming 33kV circuits, the 33/11kV transformer and the 11 kV incomer circuit breakers

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch Component[49]	Sustained Peak Demand (MVA)		Date Constraints are Binding	ICP Counts as at 2019
				2019	2029		
Karori	Winter	21	33kV cable	14.7	18.0	2022	6,052
	Summer	11	33kV cable	10.2	13.8		
8 Ira Street	Winter	21	33kV cable	15.4	18.0	2026	4,906
	Summer	15	33kV cable	12.2	16.1		
Nairn Street	Winter	22	11kV incomer cables	21.0	25.0	2021	6,852
	Summer	22	11kV incomer cables	16.6	24.7		
Not Constrained							
Evans Bay	Winter	19	33kV cable	13.9	16.0	Not constrained	4,880
	Summer	15	33kV cable	10.4	13.1		
Hataitai	Winter	22	33kV cable	14.7	18.0	Not constrained	6,817
	Summer	13	33kV cable	10.9	12.9		
Moore Street	Winter	30	33/11kV transformer	18.8	24.0	Not constrained	679
	Summer	30	33/11kV transformer	21.2	28.1		
University	Winter	25	33kV cable	17.7	19.0	Not constrained	6,286
	Summer	20	33kV cable	15.2	17.7		
Waikowhai Street	Winter	21	33kV cable	14.1	14.0	Not constrained	5,714
	Summer	13	33kV cable	9.3	11.2		

Table 8-10 Southern Area Zone Substation Capacities

At the subtransmission level, WELL's planning criterion is to maintain N-1 capacity down to the 11 kV incomer level based on equipment maximum continuous rating (MCR).[50]

A typical subtransmission circuit in the area is configured in the following manner:

- Cabling at 33 kV 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 of 50%;
- Zone substation 33 kV/11 kV supply transformers, in the continuous rating of 20-30 MVA range, fitted with oil circulation pumps and cooling fans to provide a higher cyclic rating; and

[50] Maximum continuous rating (MCR) vs cyclic capacity: MCR is used for capacity planning to cover sustained peak and cyclic rating (for a specified limited duration) is used for operations to cover short-term peak loading and contingencies.

- 11 kV cabling from the 11 kV 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.

Subtransmission constraints can be quantified in terms of duration of potential overload assessed against the security criteria 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 development needs for the Southern Area at the subtransmission and distribution level are outlined in the following sections.

8.4.2.1 8 Ira Street

The sustained peak load supplied by 8 Ira Street is currently within the N-1 capacity of the subtransmission circuits. Table 8-11 illustrates the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
8 Ira Street	Winter	21.0	15.4	0
	Summer	15.0	12.2	0

Table 8-11 Current 8 Ira Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers. Figure 8-11 shows the load duration curve against the subtransmission N-1 ratings.

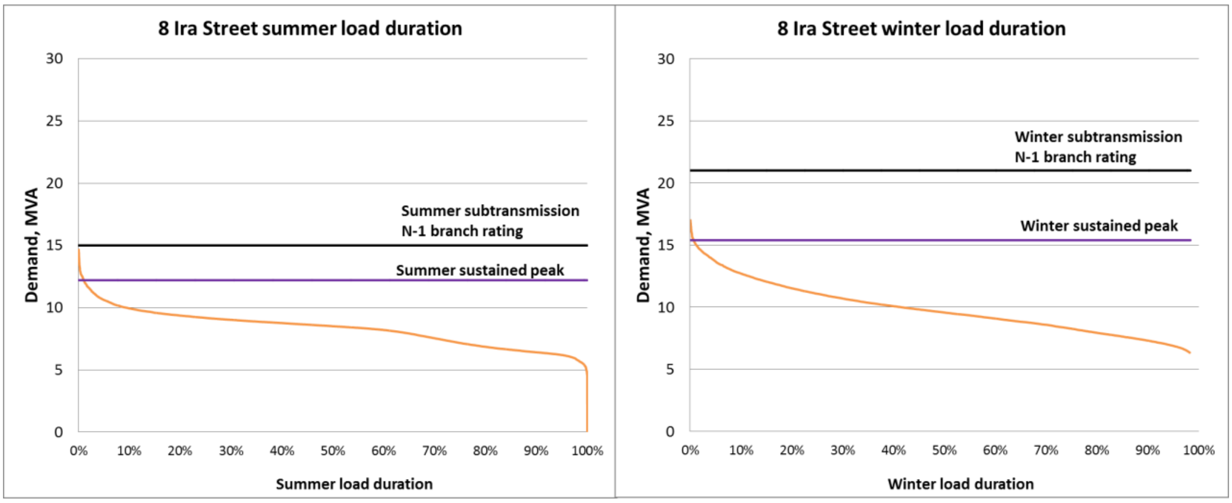


Figure 8-11 8 Ira Street Load Duration Curve

The load duration curve shows the proportion of load at risk. 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 8 Ira Street is forecasted to change as shown in Figure 8-12. The subtransmission capacity constraints are plotted for comparison. Without action, the summer load growth is forecast to breach the subtransmission N-1 capacity from 2026.

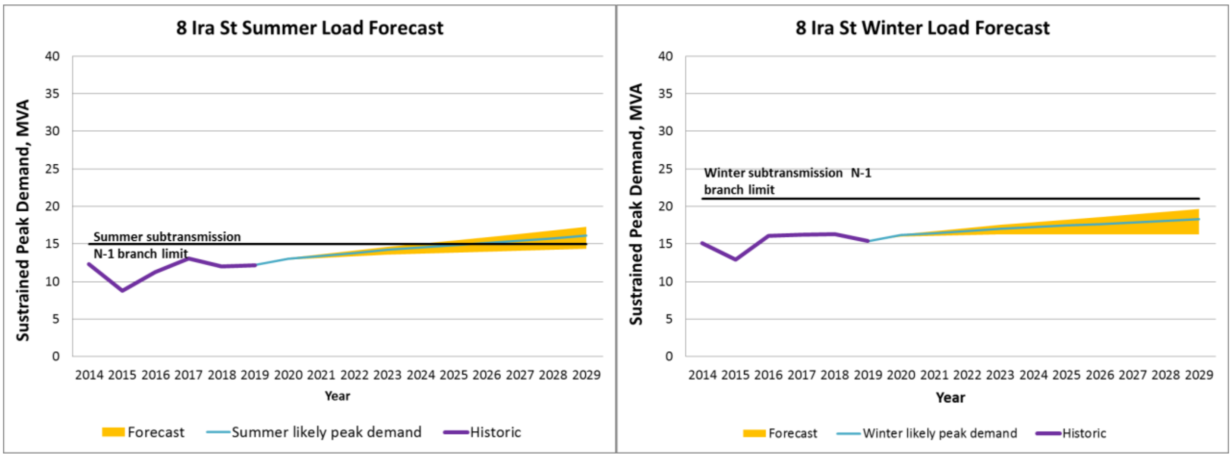


Figure 8-12 8 Ira Street Load Forecast

8.4.2.2 Evans Bay

The sustained peak load supplied from Evans Bay is currently within the N-1 capacity of the subtransmission circuits. Table 8-12 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Evans Bay	Winter	19.0	13.9	0
	Summer	15.0	10.4	0

Table 8-12 Current Evans Bay Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers through partially off-loading Evans Bay to adjacent zone substations. Figure 8-13 shows the load duration curve against the subtransmission N-1 ratings.

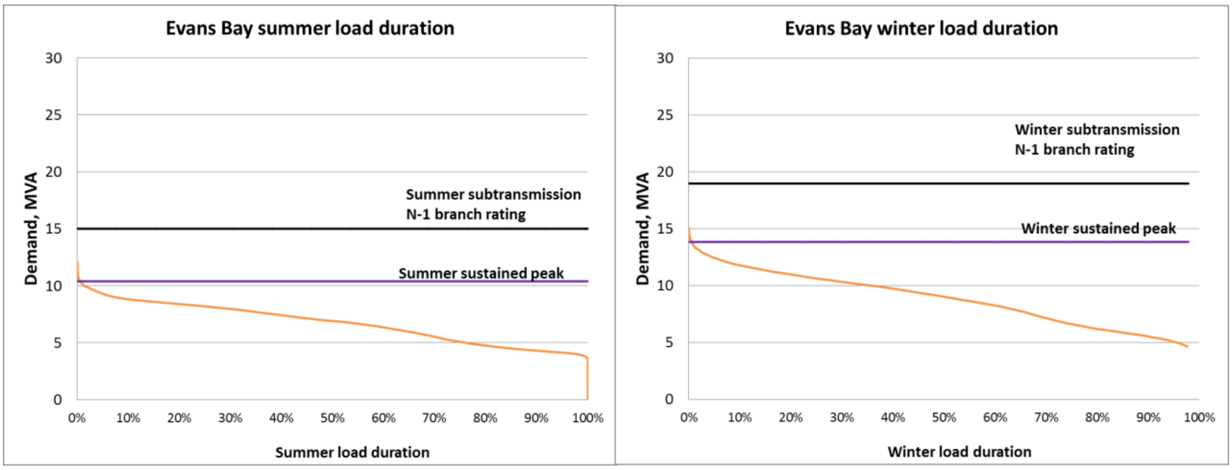


Figure 8-13 Evans Bay Load Duration Curve

The load duration curve shows the proportion of load at risk. 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 Evans Bay is forecasted to change as shown in Figure 8-14. The subtransmission capacity constraints are plotted for comparison.

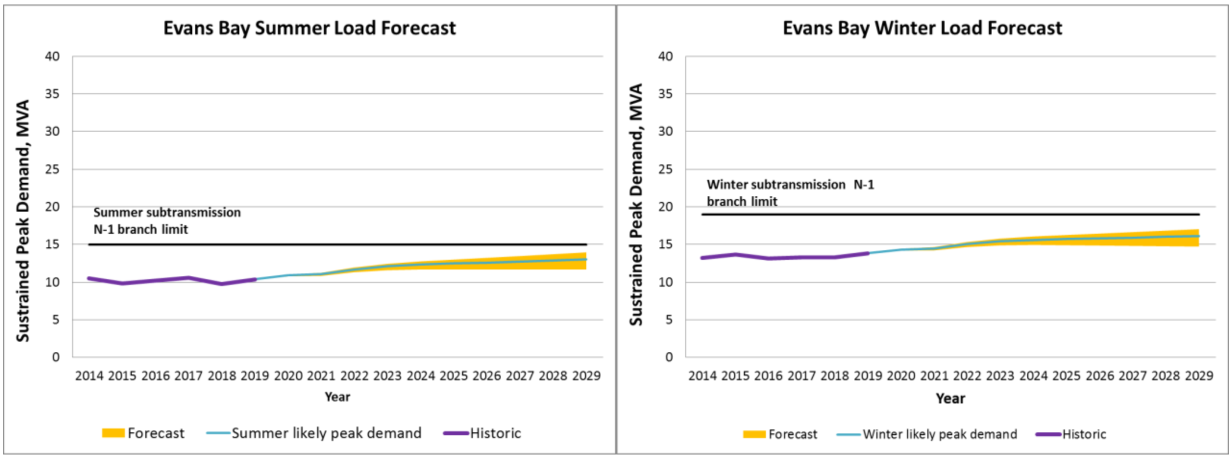


Figure 8-14 Evans Bay Load Forecast

8.4.2.3 Frederick Street

The sustained peak load supplied by Frederick Street currently exceeds the cyclic N-1 capacity of the subtransmission supply cables. Table 8-13 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Frederick Street	Winter	23.2	27.4	4.2
	Summer	19.5	21.5	2.0

Table 8-13 Current Frederick Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers through partially off-loading Frederick Street to an alternative zone substation.

Figure 8-15 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable. The load duration curve shows the proportion of load at risk. The loading exceeds the cable's N-1 summer cyclic rating for approximately 7.5% of the time in summer and the cable's N-1 winter cyclic rating for approximately 16.8% of the time in winter. This analysis uses a load duration curve based on 30 minute periods and is higher than the sustained peak.

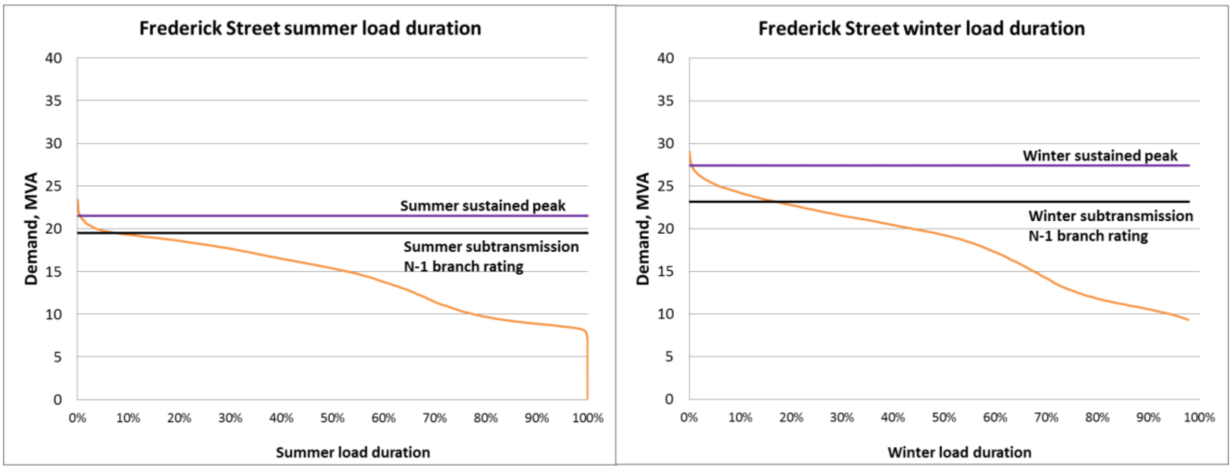


Figure 8-15 Frederick Street Load Duration Curve

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 8-16. The subtransmission capacity constraints are plotted for comparison.

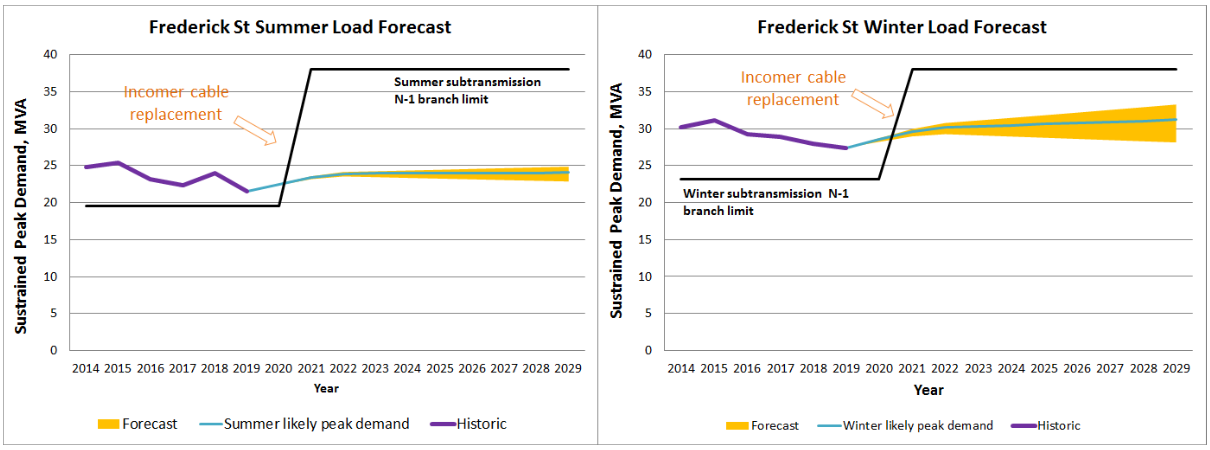


Figure 8-16 Frederick Street Load Forecast

WELL has initiated a project to replace the Frederick street subtransmission cables with higher capacity cables scheduled for completion in 2021. The upgraded Frederick Street cables also allows better load sharing between Frederick Street and The Terrace zone substations to defer The Terrace transformer replacement timeline. The 11 kV bus rating limitation will restrict load flow across the bus but this constraint is less material and can be managed by setting up a monitor.

8.4.2.4 Hataitai

The sustained peak load supplied from Hataitai is currently within the N-1 capacity of the subtransmission circuits. Table 8-14 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Hataitai	Winter	22.0	14.7	0
	Summer	13.0	10.9	0

Table 8-14 Current Hataitai Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers. Figure 8-17 shows the load duration curve against the subtransmission N-1 ratings. The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the sustained peak.

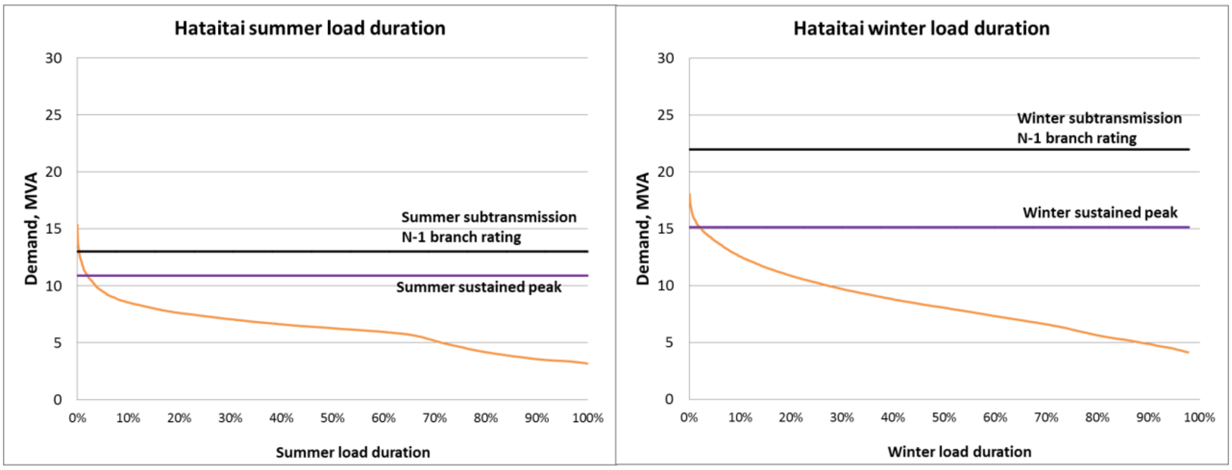


Figure 8-17 Hataitai Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Hataitai is forecasted to change as shown in Figure 8-18. The subtransmission capacity constraints are plotted for comparison.

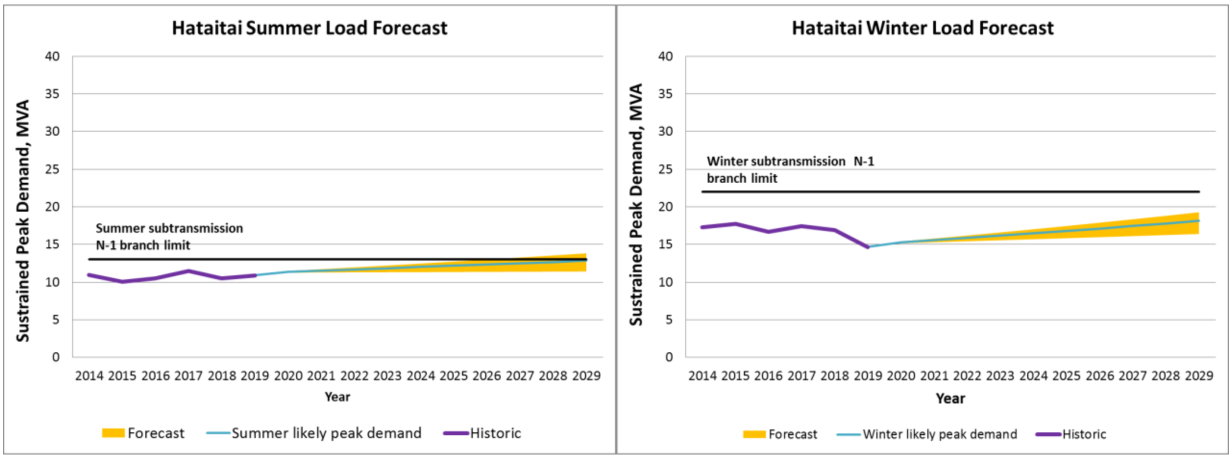


Figure 8-18 Hataitai Load Forecast

The sustained winter peak demand supplied by Hataitai is currently within the available N-1 capacity at the zone substation. However, the summer rating of the subtransmission circuits could become a constraint if the primary supply source for Wellington Hospital is transferred from Palm Grove to Hataitai.

WELL continues to monitor the load growth and will investigate options to mitigate the constraining sections through pinch point removal or other means to remove the system constraints.

8.4.2.5 Karori

The sustained peak load supplied from Karori is currently within the N-1 capacity of the subtransmission circuits. Table 8-15 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Karori	Winter	21.0	14.7	0
	Summer	11.0	10.2	0

Table 8-15 Current Karori Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers and partially off-loading Karori to an adjacent zone substations.

Figure 8-19 shows the load duration curve against the subtransmission N-1 ratings.

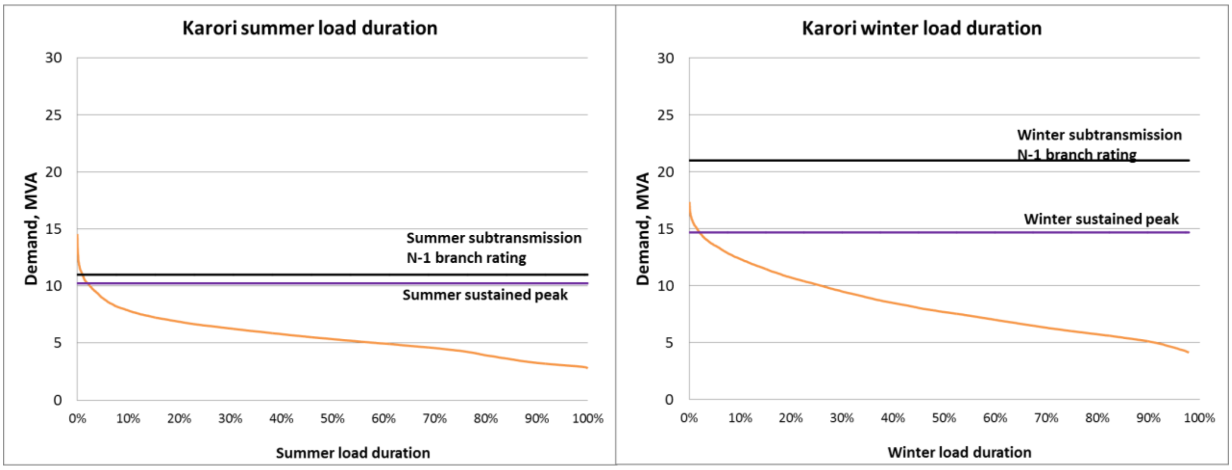


Figure 8-19 Karori Load Duration Curve

The load duration curve shows the proportion of load at risk. 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 Karori is forecasted to change as shown in Figure 8-20. The subtransmission capacity constraints are plotted for comparison. Without action, the summer load growth is forecast to breach the subtransmission N-1 capacity from 2022.

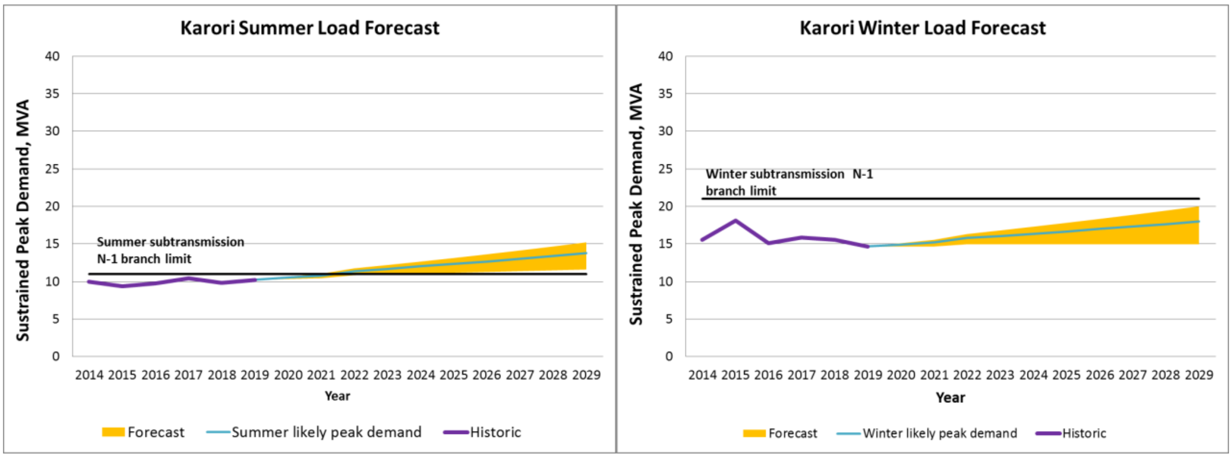


Figure 8-20 Karori Load Forecast

8.4.2.6 Moore Street

The sustained peak load supplied from Moore Street is currently within the N-1 capacity of the subtransmission circuits. Table 8-16 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Moore Street	Winter	30.0	18.8	0
	Summer	30.0	21.2	0

Table 8-16 Current Moore Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers through partially off-loading Moore Street to adjacent zone substations.

Figure 8-21 shows the load duration curve against the subtransmission N-1 ratings.

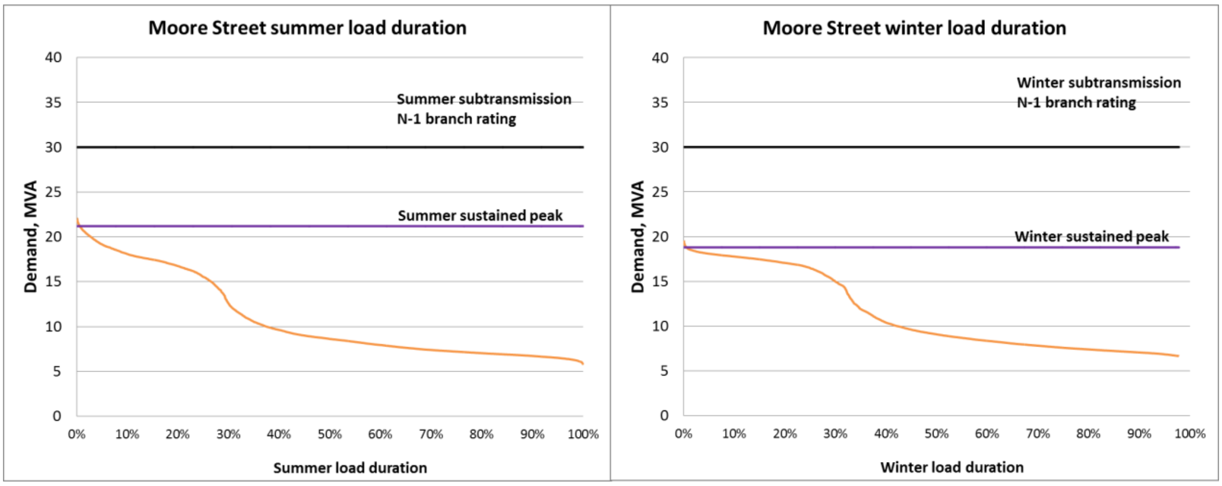


Figure 8-21 Moore Street Load Duration Curve

The load duration curve shows the proportion of load at risk. 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 Moore Street is forecasted to change as shown in Figure 8-22. The subtransmission capacity constraints are plotted for comparison.

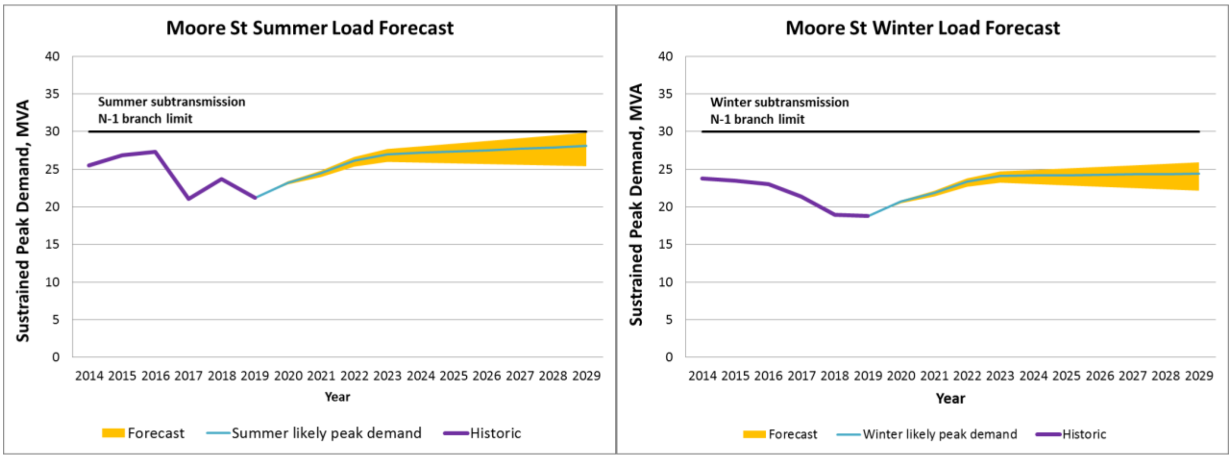


Figure 8-22 Moore Street Load Forecast

8.4.2.7 Nairn Street

The sustained peak load supplied from Nairn Street currently is within the N-1 rating of the subtransmission circuits. Table 8-17 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Nairn Street	Winter	22.0	21.0	0
	Summer	22.0	16.6	0

Table 8-17 Current Nairn Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers through partially off-loading Nairn Street to adjacent zone substation.

Figure 8-23 shows the load duration curve against the subtransmission N-1 ratings.

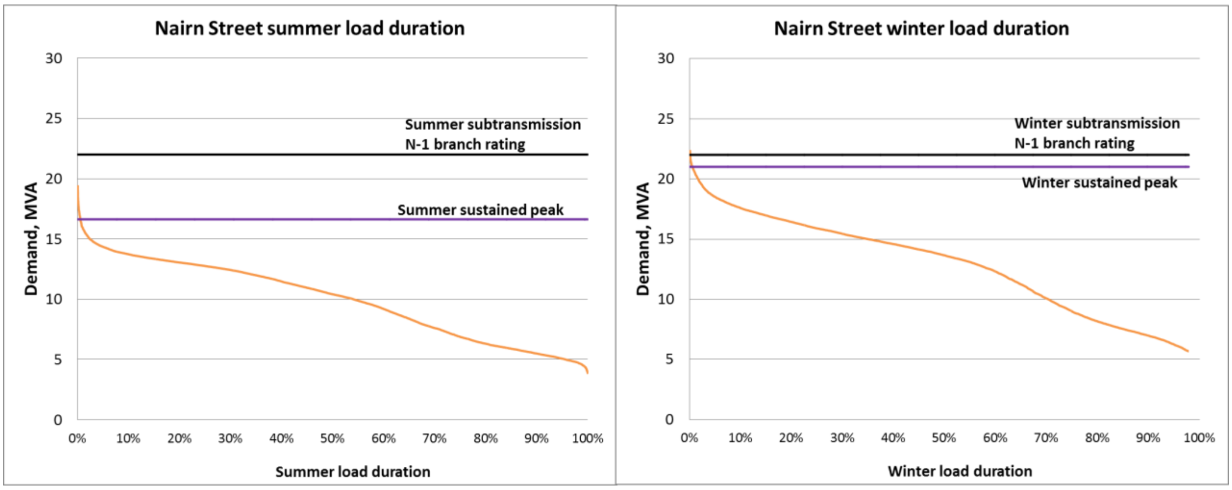


Figure 8-23 Nairn Street Load Duration Curve

The load duration curve shows the proportion of load at risk. 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 Nairn Street is forecasted to change as shown in Figure 8-24. The subtransmission capacity constraints are plotted for comparison. Without action, the winter load growth is forecast to breach the subtransmission N-1 capacity from 2021 and the summer load by 2022.

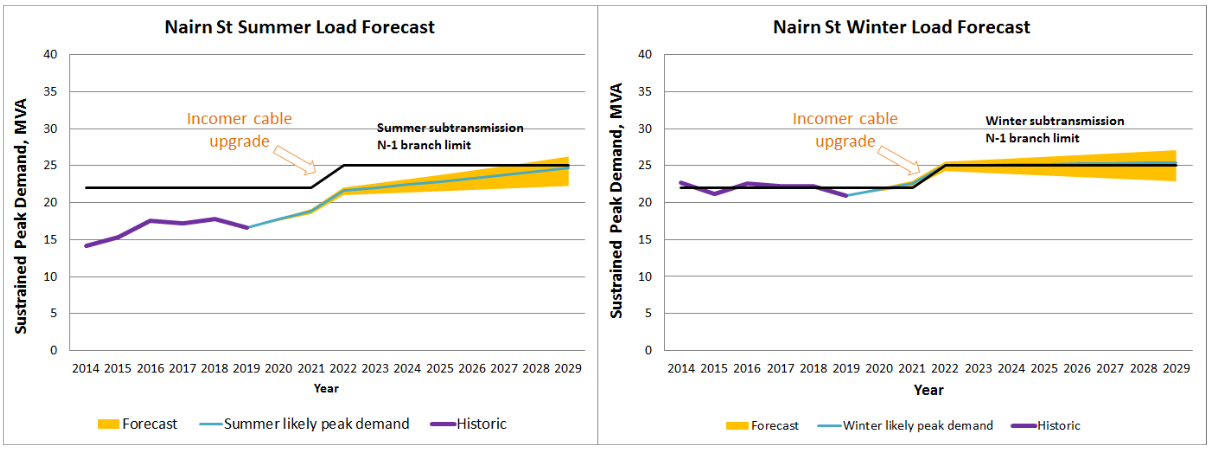


Figure 8-24 Nairn Street Load Forecast

8.4.2.8 Palm Grove

The sustained peak demand at Palm Grove currently exceeds the capacity of the two 24 MVA transformers as illustrated in Table 8-18. 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 magnitude of load at risk and duration is summarised in Figure 8-25.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Palm Grove	Winter	24.0	24.2	0.2
	Summer	24.0	17.5	0.0

Table 8-18 Current Palm Grove Subtransmission Constraints

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. WELL has regular discussions with the Capital Coast District Health Board (CCDHB) about the potential options for mitigating the security of supply and resilience risks at Wellington Hospital. In 2018 WELL completed a detailed solution design for security improvements and additional capacity. The recommended option will see the primary supply for the hospital shifted from Palm Grove to Hataitai zone substation.

CCDHB is currently building a new Children's Hospital and has also indicated high level plans to expand facilities at Wellington Hospital further within the planning period. The capacity and timing of these expansion plans are being worked through.

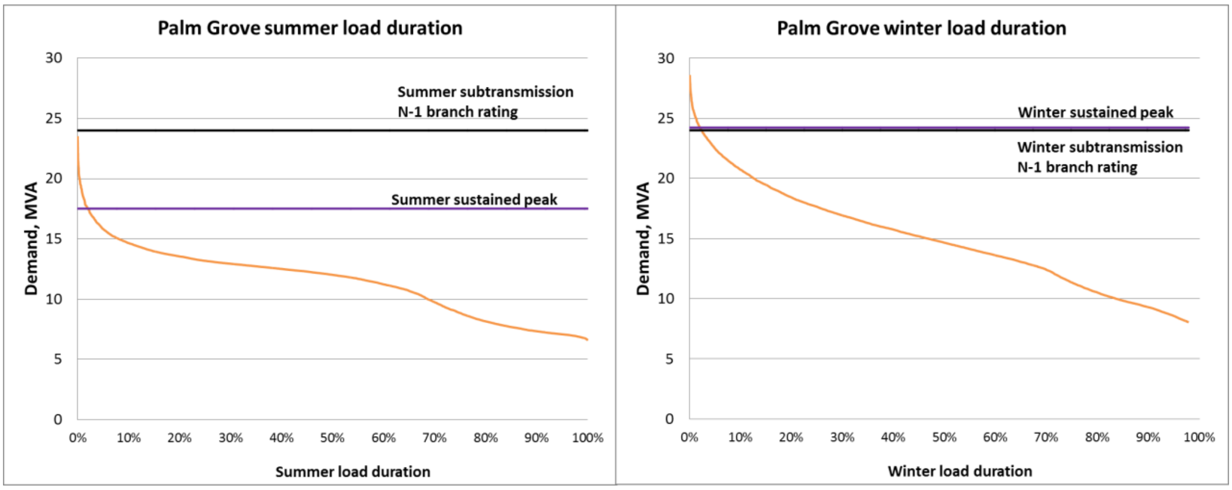


Figure 8-25 Palm Grove Load Duration

The peak demand during winter exceeds the N-1 transformer cyclic capacity for approximately 2.3% of the time during winter, which 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, as well as the impact of the additional capacity at the public hospital, private hospital and EV buses. 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 8-26. The N-1 shortfall will be managed operationally and upgrade project is scheduled to resolve the capacity constraints.

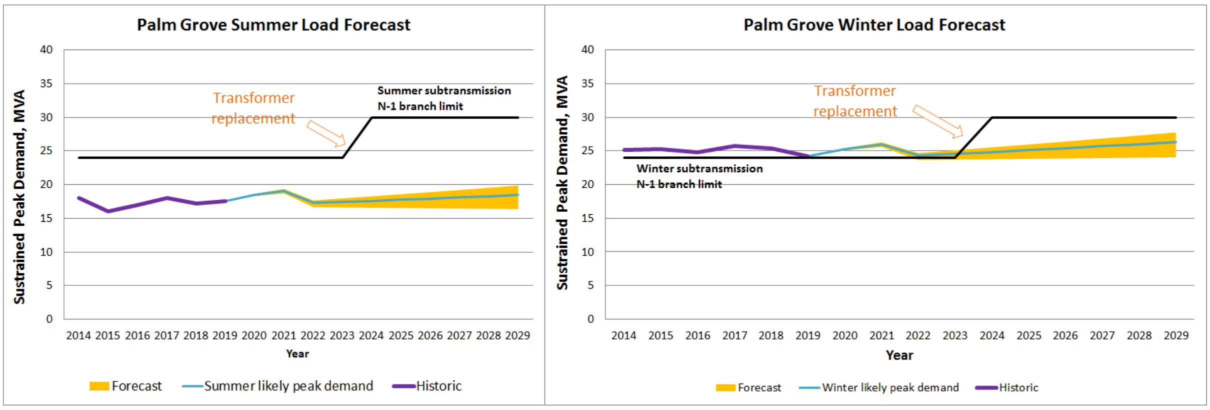


Figure 8-26 Palm Grove Load Forecast

8.4.2.9 The Terrace

The sustained peak demand at The Terrace is currently within the N-1 capacity of the subtransmission circuits as illustrated in Table 8-19.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
The Terrace	Winter	30.0	27.1	0
	Summer	30.0	29.2	0

Table 8-19 Current The Terrace Subtransmission Constraints

The load duration curve given in Figure 8-27 shows that over the last 12 month period, the loading nearly matches the transformer's N-1 cyclic capacity. This load duration curve is based on 30 minute periods.

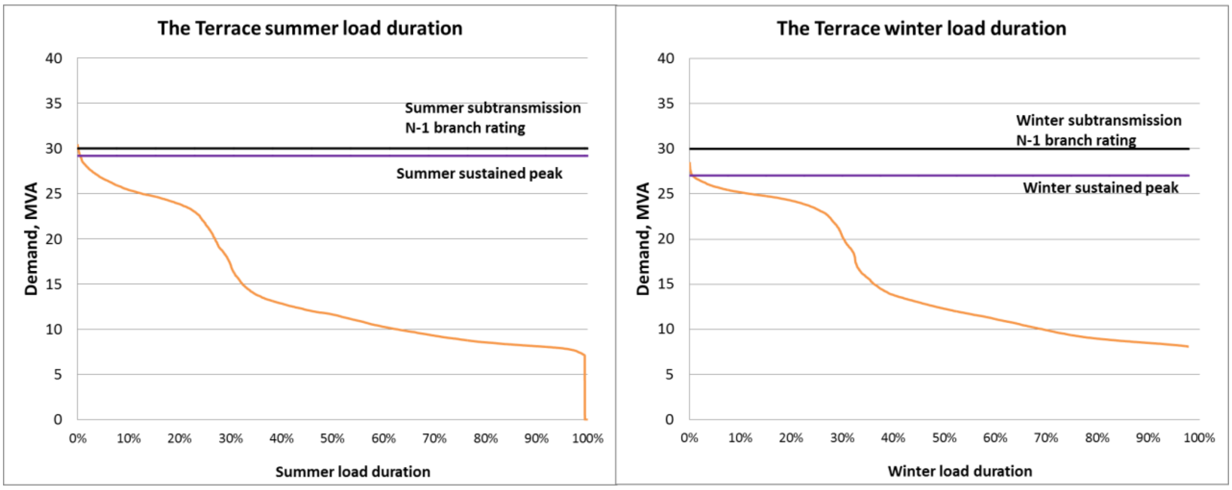


Figure 8-27 The Terrace Load Duration

The load is expected to increase as shown in Figure 8-28. The forecast summer peak load is expected to exceed the subtransmission N-1 rating by 2021. The current risk mitigation plan is to re-balance the load between Frederick Street and The Terrace after the current constraint at Frederick Street is mitigated.

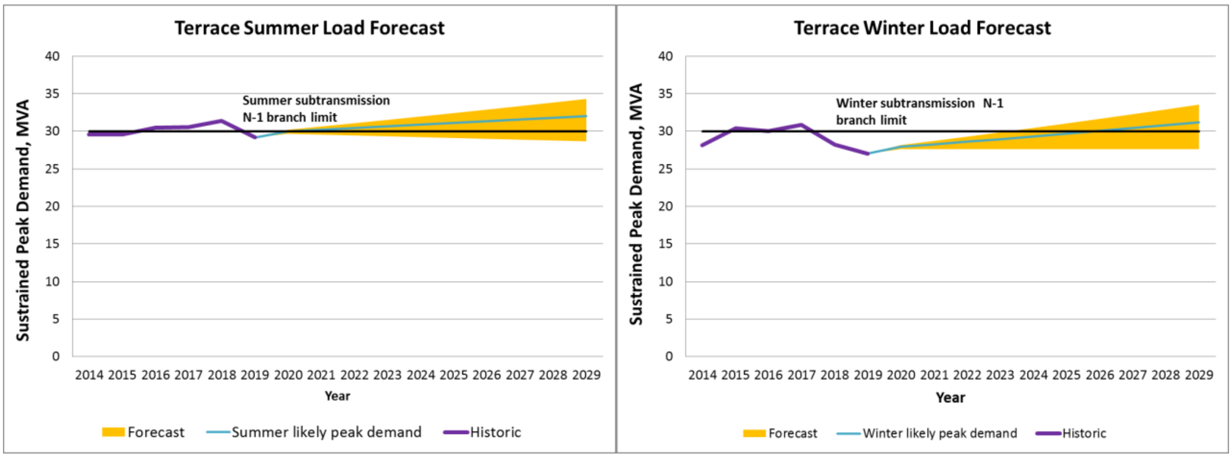


Figure 8-28 The Terrace Load Forecast

8.4.2.10 University

The sustained peak load supplied from University is currently within the N-1 capacity of the subtransmission circuits. Table 8-20 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
University	Winter	25.0	17.7	0
	Summer	20.0	15.2	0

Table 8-20 Current University Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers through partially off-loading University to adjacent zone substations.

Figure 8-29 shows the load duration curve against the subtransmission N-1 ratings.

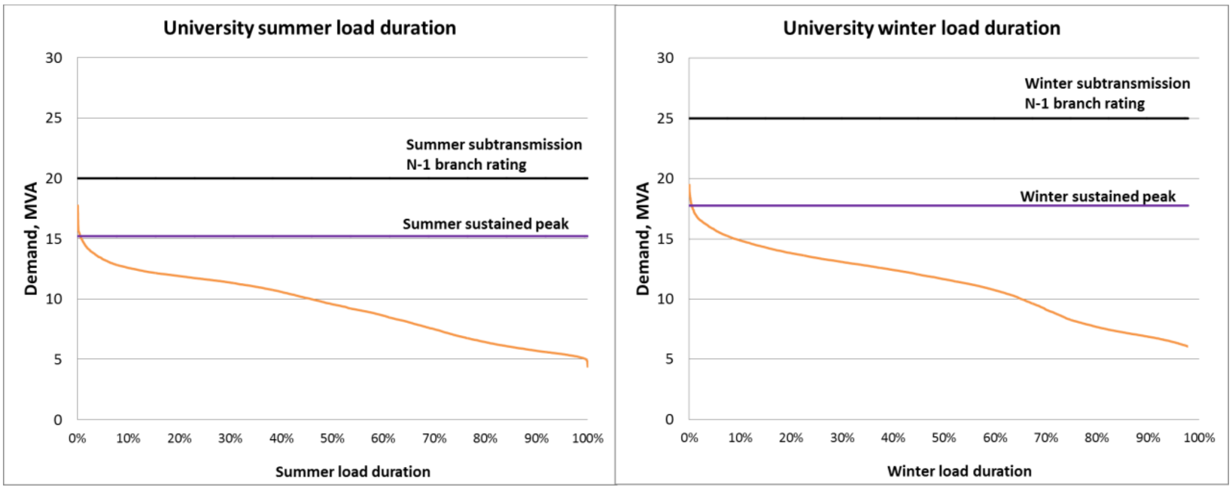


Figure 8-29 University Load Duration Curve

The load duration curve shows the proportion of load at risk. 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 University is forecasted to change as shown in Figure 8-30. The subtransmission capacity constraints are plotted for comparison.

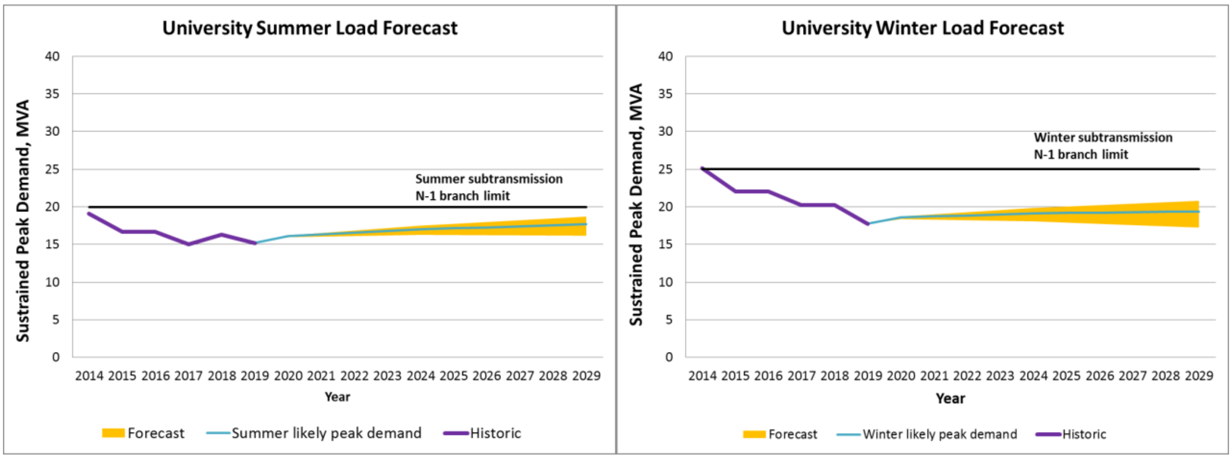


Figure 8-30 University Load Forecast

8.4.2.11 Waikowhai Street

The sustained peak load supplied from Waikowhai Street is currently within the N-1 capacity of the subtransmission circuits. Table 8-21 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Waikowhai Street	Winter	21.0	14.1	0
	Summer	13.0	9.3	0

Table 8-21 Current Waikowhai Street Subtransmission Constraints

Following a fault on the subtransmission system, WELL currently closes the 11 kV bus tie and restores supply to consumers through partially off-loading Waikowhai Street to an alternative zone substation.

Figure 8-31 shows the load duration curve against the subtransmission N-1 ratings. The load duration curve shows the proportion of load at risk. This analysis uses a load duration curve based on 30 minute periods and is higher than the sustained peak.

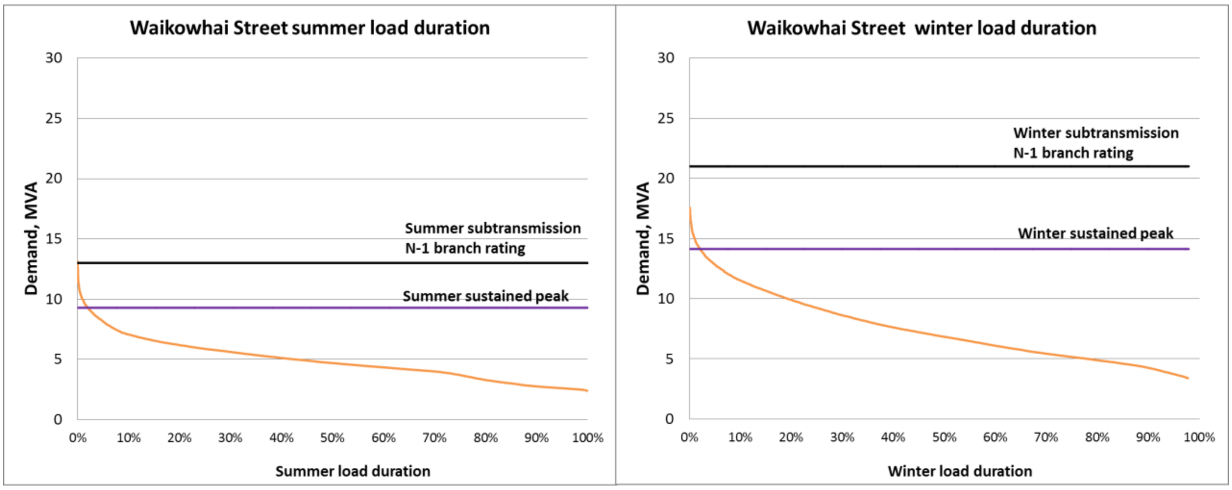


Figure 8-31 Waikowhai Street Load Duration Curve

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Waikowhai Street is forecasted to change as shown in Figure 8-32. The subtransmission capacity constraints are plotted for comparison.

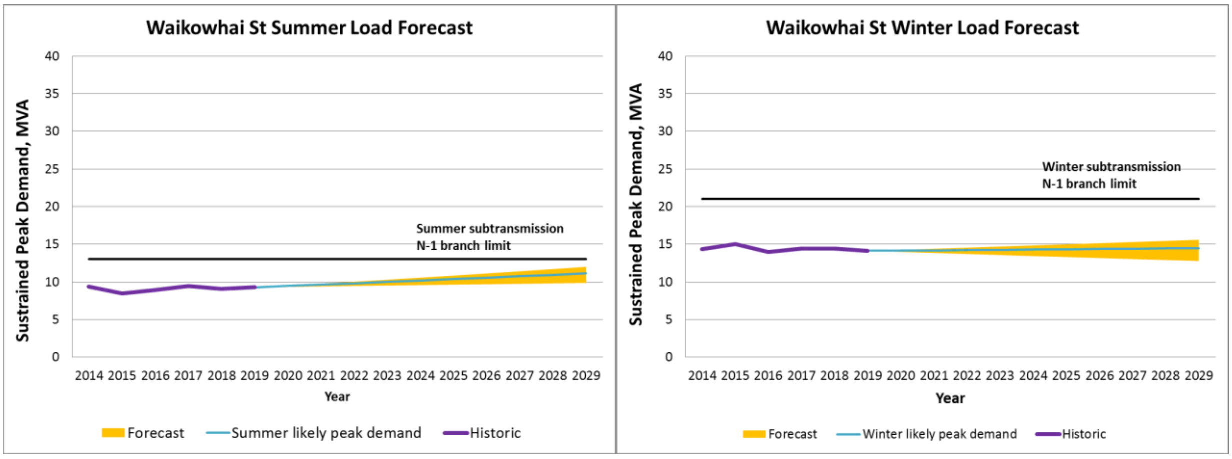


Figure 8-32 Waikowhai Street Load Forecast

8.4.3 HV Distribution Network Development Needs

The most critical distribution level issues are those associated with:

- Meshed ring feeders supplying a high number of consumers; and
- Links between zone substations which can be used for load transfer.

Table 8-22 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 is the priority level of the planning and investment requirements.

Feeder	Topology	Zone Substation	Potential Upgrade Cable Length	Present Loading	+5 years	Feeder ICP Count	Priority
Current							
EVA CB2/4	2 Fdr Mesh	Evans Bay	5,333 m	67%	79%	2,722	Low
FRE CB13/14	2 Fdr Mesh	Frederick Street	745 m	70%	83%	2,901	Low
HAI CB11	Radial	Hataitai	136 m	71%	90%	7	Low
KAR CB3/6	2 Fdr Mesh	Karori	3,040 m	72%	99%	3,662	Low
KAI CB6/7/9/10	Radial sub feeders	Kaiwharawhara	5,524 m	99%	102%	2,966	High
NAI CB 8/12	2 Fdr Mesh	Nairn Street	494 m	59%	72%	1,019	Low
NAI CB11/13	Radial sub feeder	Nairn Street	639 m	69%	82%	2,754	Low
PAL CB2/3/6	3 Fdr Mesh	Palm Grove	1,136 m	79%	110%	4,061	Medium
PAL CB8/10/12	Radial sub feeder	Palm Grove	477 m	68%	61%	5,142	Low
UNI CB12	Radial feeder	University	1,129 m	104%	132%	1,315	High
Within Five Years							
FRE CB3/4/5/8	4 feeder mesh	Frederick Street	1,252 m	Less than 67%	80%	3,374	Low
NAI CB 14	Radial	Nairn Street	2,335 m	Less than 67%	90%	1,500	Medium
NAI CB11/13	2 feeder mesh	Nairn Street	438 m	Less than 50%	59%	2,754	Low
IRA CB8/9	2 feeder mesh	8 Ira Street	3,251 m	Less than 50%	58%	411	Low
UNI CB 2	Radial	University	506 m	Less than 67%	87%	164	Low
UNI CB 13	Radial	University	303 m	Less than 67%	71%	416	Low
KAI CB3/4/5	3 feeder mesh	Kaiwharawhara	2,912 m	Less than 67%	84%	363	Low
KAI CB3/4/5	Radial section on ring	Kaiwharawhara	452 m	Less than 67%	91%	363	Low
WKW CB8	Radial	Waikowhai Street	1,334 m	Less than 67%	69%	708	Low

Feeder	Topology	Zone Substation	Potential Upgrade Cable Length	Present Loading	+5 years	Feeder ICP Count	Priority
MOO CB1/2	2 Fdr Mesh	Moore Street	709 m	Less than 50%	63%	155	Low
MOO CB3/5	2 Fdr Mesh	Moore Street	812 m	Less than 50%	60%	155	Low
KAR CB3/6	Radial sub feeder	Karori	165 m	Less than 67%	70%	3,662	Low

Table 8-22 Distribution Level Issues

Feeder protection 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 load to the remaining feeders and is designed to avoid a trip of the feeder protection relays at the zone substation.

Table 8-23 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 current sustained peak demand for each feeder.

Meshed Ring	N-1 Case	Feeder	Potential Upgrade Cable Length	Contingency Loading	Control
Current					
EVA 2/4	EVA CB02 Out	EVA CB04	1,988 m	105%	Network augmentation
	EVA CB04 Out	EVA CB02	1,561 m	133%	
FRE 13/14	FRE CB13 Out	FRE CB14	860 m	104%	Network augmentation
	FRE CB14 Out	FRE CB13	1,051 m	119%	
KAR 3/6	KAR CB03 Out	KAR CB06	1,935 m	139%	Network augmentation
	KAR CB06 Out	KAR CB03	1,106 m	124%	
PAL 2/3/6	PAL CB02 Out	PAL CB06	1,136 m	103%	Optimise open points and monitor growth
	PAL CB03 Out	PAL CB02	836 m	109%	
	PAL CB06 Out	PAL CB02	3,319 m	113%	
PAL 8/10/12	PAL CB10 Out	PAL CB8	502 m	101%	Network augmentation
TER 3/4/5/6	TER CB05 Out	TER CB06	848 m	107%	Optimise open points and monitor growth
Within 5 years					
IRA 8/9	IRA CB08 Out	IRA CB09	2,473 m	135%	Optimise open points and monitor growth

Meshed Ring	N-1 Case	Feeder	Potential Upgrade Cable Length	Contingency Loading	Control
FRE 3/4/5/8	FRE CB03 Out	FRE CB08	534 m	110%	Optimise open points and monitor growth
	FRE CB04 Out	FRE CB08	534 m	111%	
	FRE CB05 Out	FRE CB08	534 m	102%	
	FRE CB08 Out	FRE CB04	752 m	104%	
KAI 3/4/5	KAI CB03 Out	KAI CB04	530 m	121%	Optimise open points and monitor growth
	KAI CB04 Out	KAI CB03	3,369 m	105%	
	KAI CB05 Out	KAI CB04	2,912 m	116%	
MOO 1/2	MOO CB01 Out	MOO CB02	1,525 m	101%	Optimise open points and monitor growth
	MOO CB02 Out	MO CB01	2,661 m	101%	
MOO 3/5	MOO CB03 Out	MOO CB05	64 m	102%	Optimise open points and monitor growth
	MOO CB05 Out	MOO CB03	1,022 m	102%	
NAI 8/12	NAI CB08 Out	NAI CB12	494 m	104%	Optimise open points and monitor growth
	NAI CB12 Out	NAI CB08	1,292 m	105%	
NAI 11/13	NAI CB11 Out	NAI CB13	1,201 m	100%	Optimise open points and monitor growth
	NAI CB13 Out	NAI CB11	1,578 m	100%	
PAL 2/3/6	PAL CB02 Out	PAL CB03	1,595 m	126%	Optimise open points and monitor growth
	PAL CB03 Out	PAL CB06	1,136 m	116%	
	PAL CB06 Out	PAL CB03	3,621	111%	
TER 3/4/5/6	TER CB06 Out	TER CB05	260 m	105%	Optimise open points and monitor growth
UNI 1/4/6	UNI CB04 Out	UNI CB01	1,332 m	102%	Optimise open points and monitor growth

Table 8-23 Meshed Ring Feeder Contingency Analysis

8.4.4 Summary of Network Development Plan

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 because there are options that meet several needs for the same investment.

8.4.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions to defer investment discussed in Section 8.1.8.

8.4.4.2 Projects for 2020/21

Projects currently underway or planned to start over the next 12 months are listed in Table 8-24.

Project	Description
Frederick Street 33 kV Cable	Replacement of two gas-filled 33kV cables from Central Park to Frederick Street, to resolve the capacity constraint identified in Section 8.4.2.3. Detailed design, consenting and procurement will occur during 2020.
Evans Bay 33 kV Bus	Construction of a 33kV bus at Evans Bay substation. Detailed design and procurement will occur during 2020
261 Darlington Road	Distribution transformer capacity upgrade.
29 Grey Street	Distribution transformer capacity upgrade.

Table 8-24 Southern Area Projects for 2020/21

8.4.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 8-25. This information is an extract from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example some subtransmission constraints can be solved through 11 kV distribution level configuration change or managed operationally.

Detailed project planning and option engineering will be completed at the project scope development and approval stage. Each identified network issue is assigned with an issue ID and all potential solutions that can resolve the issue is given an option ID that is linked to the issue ID.

Issue ID	Category	Constraint	Preferred Option	Investment Period	Investment Amount (M)
A1I1	SUBT	FRE 33kV subtransmission capacity	Two new 33 kV FRE cables 1000mm^2 AL CPK - FRE	2020-2022	$7.5
A1I2	DIST	FRE 13/14 ring feeder capacity	Reuse old 33 kV cable at 11 kV and install new CB at ZS and Bidwill St to create a new feeder	2027	$0.6
A1I3	SUBT	TER 33/11 kV transformer capacity	Permanently transfer some load away (Transfer load to UNI, FRE (after 33 kV cable upgrade, KAI)	2022	$0
A1I3	SUBT	TER 33/11 kV transformer capacity	Build Bond Street ZS	2028-2032	$33
A1I4	SUBT	TER 33 kV subtransmission capacity	Same as A1I3	2022	$0

Issue ID	Category	Constraint	Preferred Option	Investment Period	Investment Amount (M)
A1I5	DIST	KAI 6/7/9/10 ring feeder capacity	Work with the customer to build dedicated feeders from NGA – Site	2023	$0.8
A1I6	DIST	KAR 3/6 ring feeder capacity	Break KAR 8/10 feeder ring and use KAR10 cable for a third feeder into the KAR3/6 ring with feeder swap	2021	$0.3
A1I7	SUBT	FRE 11 kV bus rating	Maintain bus arrangement, monitor and limit current flow	2021	$0.2
A1I8	SUBT	KAR 33 kV subtransmission capacity	Transfer load to UNI through UNI8/10 follow UNI8/10 reconfiguration plan	2022	$0
A1I9	DIST	UNI 8/10 ring feeder	Transfer load to WKW 6 and MOO11 and rebalance to KAI 12/13/15/16	2022	$0
A1I10	DIST	UNI 12 feeder	Investigate the spare UNI3 cable that terminates to the same sub	2022	$0
A2I1	SUBT	EVA 1 33 kV cable condition	EVA 33 kV Bus	2020-2022	$4.5
A2I2	DIST	EVA 2/4 ring feeder capacity	Transfer some load to IRA01 - Open Clamperdown CB04 and close Napier Street S0055-1. Also transfer load to IRA11.	2020	$0
A2I2	DIST	EVA 2/4 ring feeder capacity	Add a three bay panel at bus section CB at Clamperdown switchboard	2023	$0.4
A2I3	SUBT	PAL 33/11 kV transformer capacity	Upgrade PAL transformer capacity - replace existing with 36 MVA units	2023-2025	$4.5
A2I3	SUBT	HAT 33 kV cable capacity	Transfer load between PAL and HAT through a new tie point at hospital, work with hospital on expansion plan	2025	$0.6
A2I4	DIST	PAL 8/10/12 ring feeder capacity	New feeder tie between PAL11 (109 Quebec St) and PAL08 (PE at 84 Frobisher Street)	2026	$1.4
A2I5	SUBT	NAI 11 kV incomer capacity	Increase incomer capacity by running two additional 630 mm^2 Cu cables (to make 4x per phase)	2021	$0.3
A2I6	DIST	NAI 11/13 ring feeder capacity	NAI13/14: Transfer load to adjacent feeders UNI11 - Open CB 1 at St Johns and close UNI CB11	2020	$0
A2I7	SUBT	HAT 33 kV subtransmission capacity	Identify and remove pinch points.	2024	$0.6
A2I8	SUBT	IRA 33 kV subtransmission capacity	Use IRA – EVA ties to manage peak demand during contingency. Monitor load growth in the next five years.	2026	$0

Table 8-25 Southern Area Development Summary

8.5 Northwestern Area NDRP

This section provides a summary of the Northwestern Area NDRP.

8.5.1 GXP Development Plans

The Northwestern Area is supplied from two GXPs, Takapu Road and Pauatahanui. The transformer capacity and the sustained maximum demand are set out in Table 8-26.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Maximum Demand (MVA)	
			2019	2029
Takapu Road 33 kV	2x90	111 / 116	89	118
Pauatahanui 33 kV	2x20	22 / 24	17	27
Total (after diversity)	-	-	**106**	**143**

Table 8-26 Northwestern Area GXP Capacities

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Transmission Planning Report.

The development need at each GXP is discussed further below.

8.5.1.1 Takapu Road

The Takapu Road GXP comprises two parallel 110/33 kV transformers each nominally rated at 90 MVA with a winter N-1 cyclic capacity of 116 MVA. The sustained maximum demand on the Takapu Road GXP in 2019 was 89 MVA. Takapu Road supplies zone substations at Waitangirua, Porirua, Kenepuru, Tawa, Ngauranga and Johnsonville each via double 33 kV circuits.

WELL 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 Road GXP are on a 110 kV double circuit tower line. The line is owned and maintained by Transpower. WELL started working with Transpower on long term supply configuration options in 2019 and it is currently in the option shortlisting stage. Possible options include:

- Maintaining status quo;
- New 33 kV subtransmission assets from either the same supply point or an alternative supply point; and
- Partial decommissioning and reinforcement.

In 2020 WELL will continue this discussion with Transpower and finalise the solution through a more detailed investigation.

8.5.1.2 Pauatahanui

Pauatahanui is supplied from the Takapu Road GXP via two 110 kV circuits. The GXP comprises two parallel 110/33 kV transformers rated at 20 MVA each. The Pauatahanui GXP supplies the Mana and Plimmerton zone substations via a single 33 kV overhead circuit connection to each substation. Mana and Plimmerton zone substations are linked at 11 kV providing a degree of redundancy should one of the 33 kV connections be out of service.

Transpower has identified that the Pauatahanui supply transformers are approaching end-of-life and that asset renewal or replacement will be required within the next 5-10 years. Potential housing and small industrial development in Plimmerton (Porirua City's Northern Growth Area) may add up to 7 MVA to the peak demand over a 15 year period, which may cause Pauatahanui GXP loading to exceed the N-1 rating of existing transformers. At the time of replacement a capacity upgrade will be required, with the future ratings still to be determined. WELL will work with Transpower on developing options that provide the most benefits to meet supply requirements.

WELL will also consider an upgrade of the subtransmission differential protection from this site within the planning period.

8.5.2 Subtransmission Network Development Needs

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 33 kV circuits supplying eight zone substations. Each zone substation supplies the respective zone 11 kV distribution network with inter-connectivity via switched open points to adjacent zones. All 11 kV 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 load summary of each zone substation is listed in Table 8-27.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch Component	Sustained Peak Demand (MVA)		Date Constraints are Binding	ICP Count as at 2019
				2019	2029		
Existing constraints							
Johnsonville	Winter	16.0	33kV cable	19.5	26.0	Existing	8,638
	Summer	11.0	33kV cable	13.7	19.1		
Mana	Winter	7.0	11kV MAN-PLI bus-tie	8.7	14.0	Existing	4,446
	Summer	7.0	11kV MAN-PLI bus-tie	6.1	10.0		
Plimmerton	Winter	7.0	11kV MAN-PLI bus-tie	8.1	13.0	Existing	2,337
	Summer	7.0	11kV MAN-PLI bus-tie	5.9	8.4		

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch Component	Sustained Peak Demand (MVA)		Date Constraints are Binding	ICP Count as at 2019
				2019	2029		
Porirua	Winter	16.0	33/11kV transformer	20.9	21.0	Existing	3,769
	Summer	14.0	33kV cable	15.8	16.6		
Forecasted constraints							
Ngauranga	Winter	10.0	33/11kV transformer	9.7	17.0	2021	4,368
	Summer	10.0	33/11kV transformer	6.9	15.6		
Kenepuru	Winter	18.3	33/11kV transformer	10.9	19.0	2021	2,196
	Summer	13.7	33kV cable	9.5	18.8		
Tawa	Winter	16.0	33/11kV transformer	14.2	22.0	2022	5,305
	Summer	14.0	33kV cable	10.5	17.4		
Waitangirua	Winter	16.0	33/11kV transformer	13.5	18.0	2027	5,867
	Summer	15.0	33kV cable	9.6	13.9		

Table 8-27 Northwestern Area Zone Substation Capacities

The development needs for the Northwestern Area at the subtransmission and distribution level are outlined in the following sections.

Subtransmission constraints can be quantified in terms of duration of risk and assessed against the security criteria in Table 8-1, using a load duration curve. Forecasted constraints are quantified in terms of when the risk is likely to occur based on the forecast demand for a given year.

The zone substations that are forecast to be constrained during the planning period are described below.

8.5.2.1 Johnsonville

The sustained peak load supplied by Johnsonville currently exceeds the N-1 capacity of the subtransmission circuits. Operational risk is currently managed by load control and transfer to HV feeders from other zone substations. Table 8-28 illustrates the seasonal constraint levels and the minimum off load requirements.

safer together

Zone substation	Season	Subtransmission N-1 Constraining N-1 branch rating (MVA)rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Johnsonville	Winter	16.0	19.5	3.5
	Summer	11.0	13.7	2.7

Table 8-28 Current Johnsonville Subtransmission Constraints

Figure 8-33 shows the load duration curve against the N-1 ratings of Johnsonville subtransmission circuits. The load duration curves shows that at present the demand exceeds the firm capacity about 14% of the time over the winter period and 10% of the time over the summer period. This exceeds the network security standard for a mixed commercial and residential zone substation.

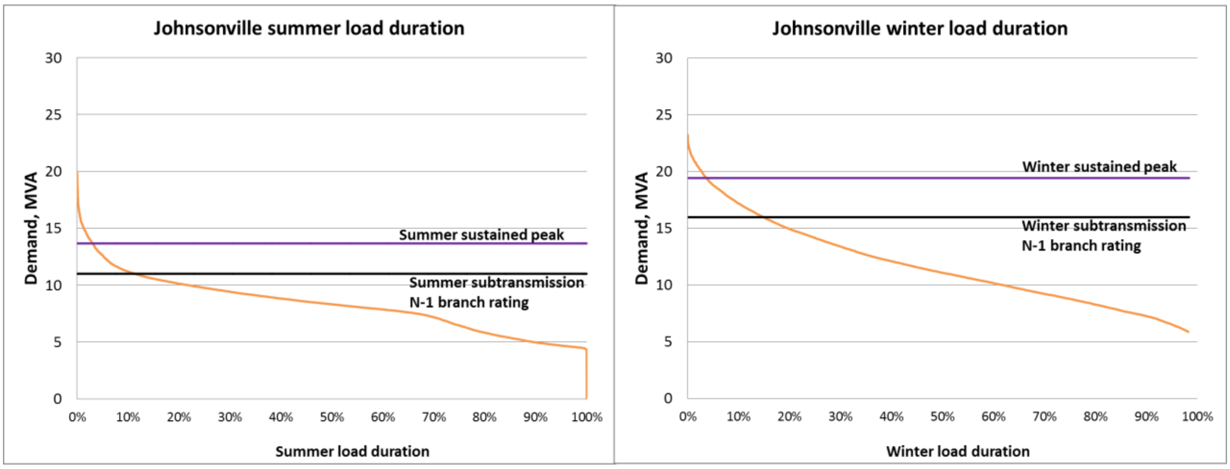


Figure 8-33 Johnsonville Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Johnsonville is forecasted to grow as shown in Figure 8-34. The forecast load growth is expected to come from significant proposed commercial development in 2023 and will require action to mitigate as discussed in Section 8.5.4.

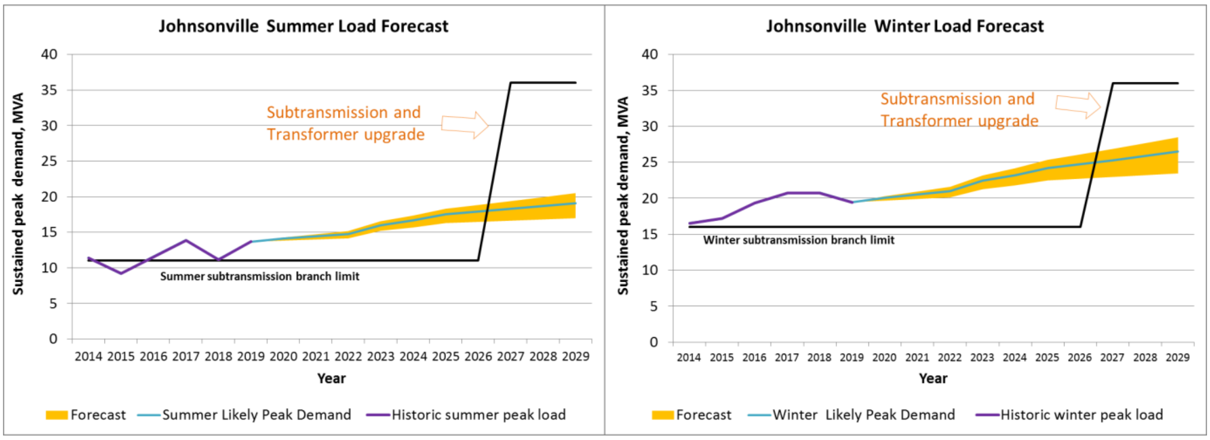


Figure 8-34 Johnsonville Load Forecast

8.5.2.2 Kenepuru

Maximum demand at Kenepuru is within available N-1 subtransmission capacity. It is forecasted that with growth, the sustained summer peak demand could exceed the N-1 cyclic capacity by 2021. Table 8-29 illustrates the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Kenepuru	Winter	18.3	10.9	0
	Summer	13.7	9.5	0

Table 8-29 Current Kenepuru Subtransmission Constraints

Figure 8-35 shows the load duration curve against the N-1 ratings of the Kenepuru subtransmission circuits. The load duration curve shows that at present the demand is below the firm capacity.

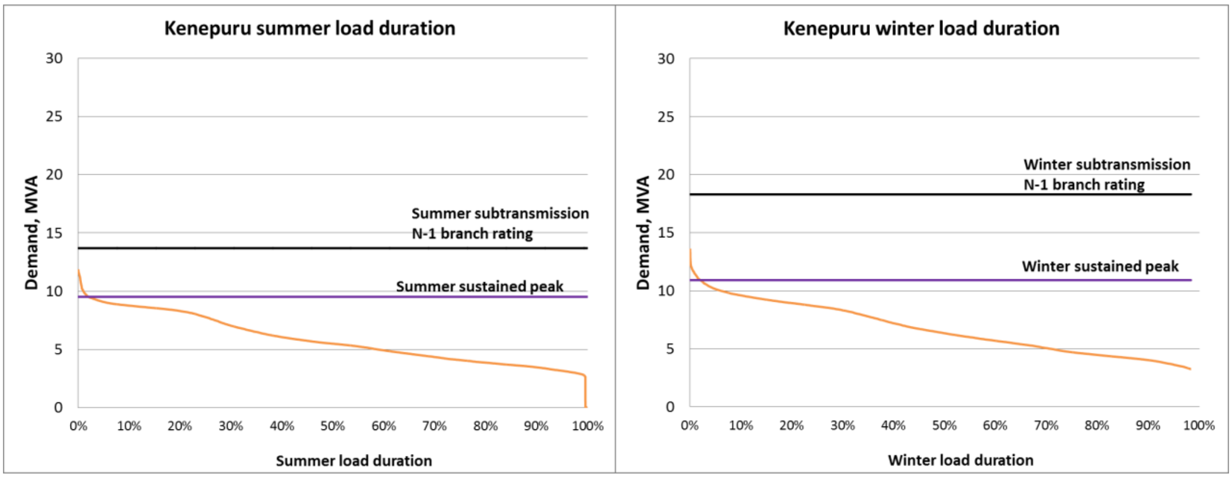


Figure 8-35 Kenepuru Load Duration

Forecasted load growth will come from a new residential sub-division, a retirement village, hospital expansion and industrial load from a factory expanding operations. Figure 8-36 shows the forecast demand for Kenepuru zone substation.

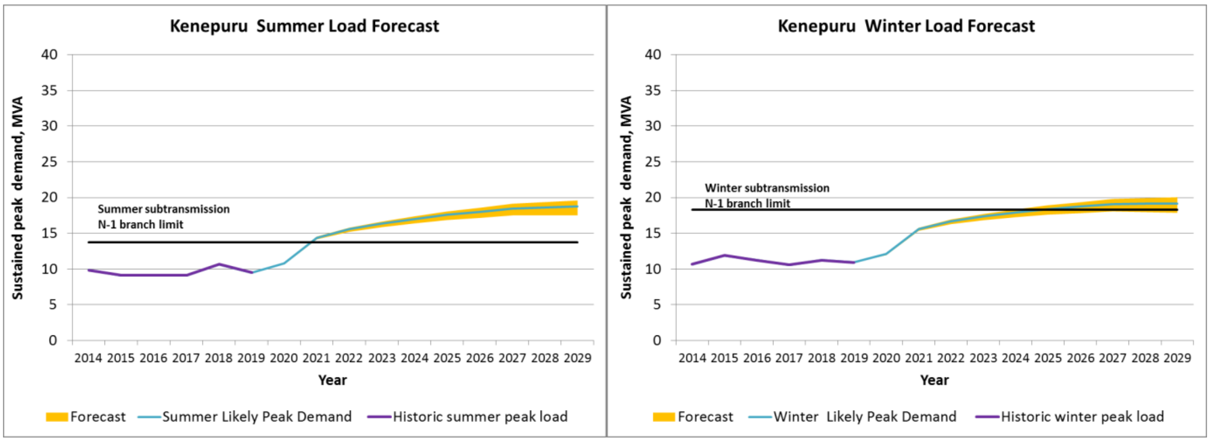


Figure 8-36 Kenepuru Load Forecast

8.5.2.3 Ngauranga

At present, the winter maximum demand at Ngauranga is approximately the same as the N-1 subtransmission capacity. This is still within the loading security criteria for this zone substation.

Table 8-30 illustrates the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Ngauranga	Winter	10.0	9.7	0
	Summer	10.0	6.9	0

Table 8-30 Current Ngauranga Subtransmission Constraints

Figure 8-37 shows the load duration curve against the N-1 ratings of the subtransmission circuits for Ngauranga. The load duration curve shows that at present the demand exceeds the firm capacity for less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

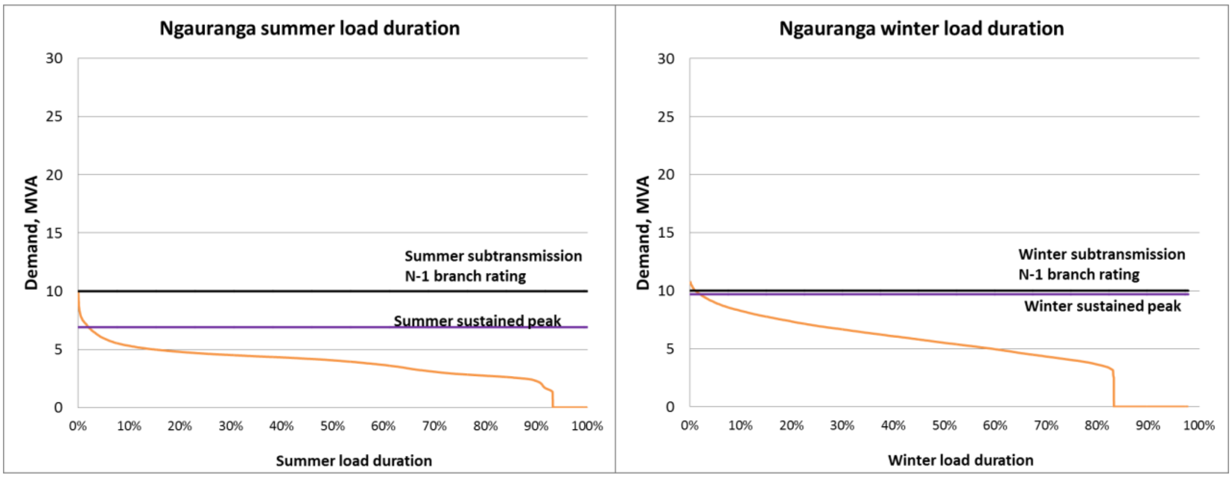


Figure 8-37 Ngauranga Load Duration

Transfer of primary supply for the abattoirs load from Kaiwharawhara to Ngauranga is expected to raise the sustained peak demand above the subtransmission N-1 capacity in 2020. The issues will be resolved with the scheduled transformer replacement that will install higher capacity units. Figure 8-38 shows the forecast demand for Ngauranga zone substation.

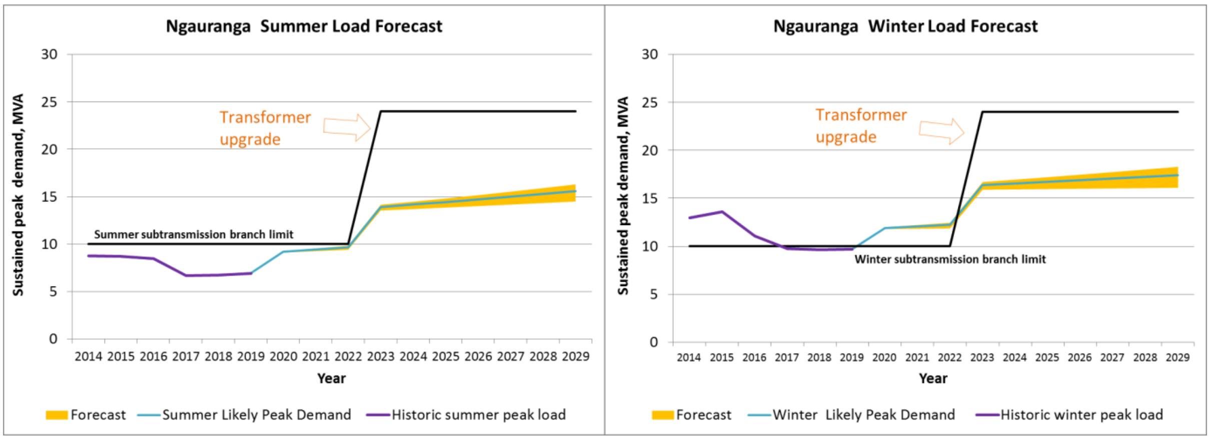


Figure 8-38 Ngauranga Load Forecast

8.5.2.4 Mana

The Mana zone substation is supplied via a single subtransmission circuit (i.e. a single 33/11 kV transformer and 33 kV circuit from Pauatahanui GXP). The Mana zone substation demand is below the capacity of this single subtransmission circuit.

The 11 kV buses of the Mana and Plimmerton zone substations are connected via an 11 kV bus tie cable to provide up to 7 MVA backfeed capacity between the two zone substations. When the single 33 kV circuit supplying Mana zone substation is out of service, the amount of load at Mana zone substation that can be supplied from the 11 kV bus-tie to Plimmerton zone substation will be limited to ensure the combined Mana and Plimmerton load does not exceed the capacity of the single subtransmission circuit at Plimmerton. This may require transferring some of the Mana load to other zone substations, as summarised in Table 8-31.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Mana	Winter	7.0	8.7	1.7
	Summer	7.0	6.1	0

Table 8-31 Current Mana Subtransmission Constraints

Figure 8-39 shows the load duration curve against the N-1 subtransmission capacity for Mana (assuming maximum bus-tie capacity of 7 MVA). The load duration plot shows the peak demand at Mana exceeds the available capacity of the bus-tie approximately 12.4% in winter. This load duration curve is based on 30 minute periods and is higher than the sustained peak.

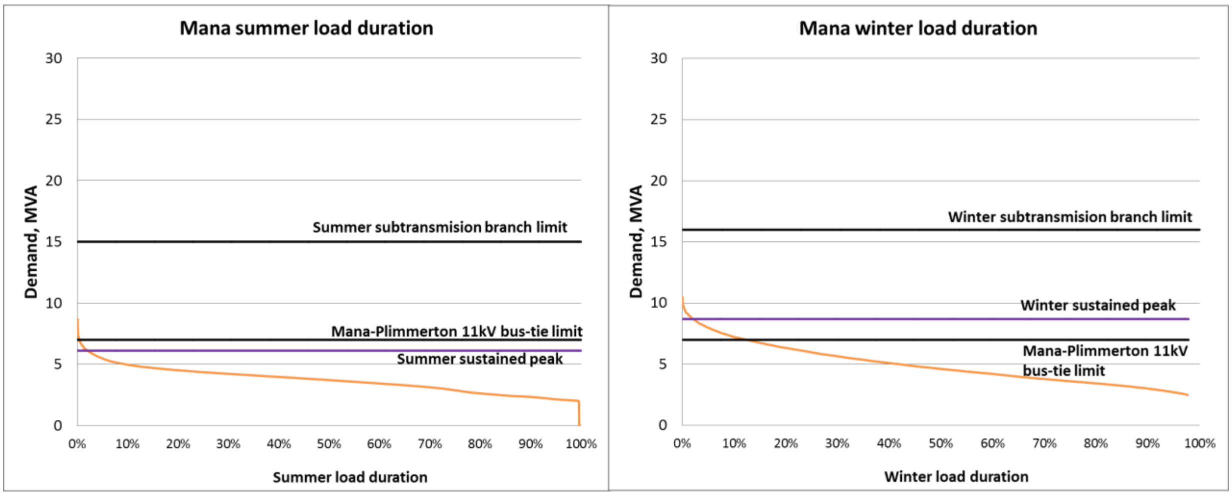


Figure 8-39 Mana Load Duration

Figure 8-40 shows the forecast demand for Mana zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

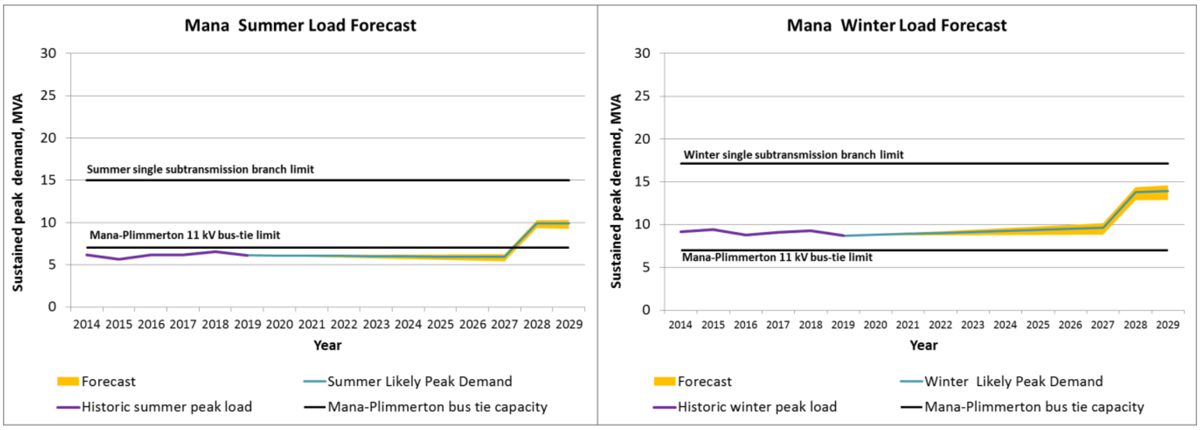


Figure 8-40 Mana Load Forecast

In the short term, WELL 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 will be less effective.

The load forecast shows that a proportion of load is at risk in the winter periods and a summer constraint may occur if the signalled residential and small industrial development in the area proceeds. The magnitude and timing of the risk will also be driven by the load growth due to development of residential subdivisions in the Whitby and Aotea areas. The new development will also impact the network security and available capacity at Porirua, Waitangirua zone substations and HV feeders in the area.

8.5.2.5 Plimmerton

The Plimmerton zone substation is supplied via a single subtransmission circuit (i.e., a single 33/11 kV transformer and 33 kV circuit from Pauatahanui GXP). The Plimmerton zone substation demand is below the capacity of this single subtransmission circuit.

The 11 kV buses of Mana and Plimmerton zone substations are connected via an 11 kV bus tie cable to provide up to 7 MVA backfeed capacity between the two zone substations. When the single 33 kV circuit supplying Plimmerton zone substation is out of service, the amount of load at Plimmerton zone substation that can be supplied from the 11 kV bus-tie to Mana zone substation will be limited to ensure the combined Mana and Plimmerton load does not exceed the capacity of the single subtransmission circuit at Mana. This may require transferring some load to other zone substations, as summarised in Table 8-32.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Plimmerton	Winter	7.0	8.1	1.1
	Summer	7.0	5.9	0

Table 8-32 Current Plimmerton Subtransmission Constraints

Figure 8-41 shows the load duration curve against the N-1 ratings of the Plimmerton subtransmission circuits (assuming maximum bus-tie capacity of 7 MVA). The load duration curve shows that at present the winter peak demand exceeds the firm capacity about 8.2% of the time. This exceeds the network security standard for a mixed commercial and residential zone substation.

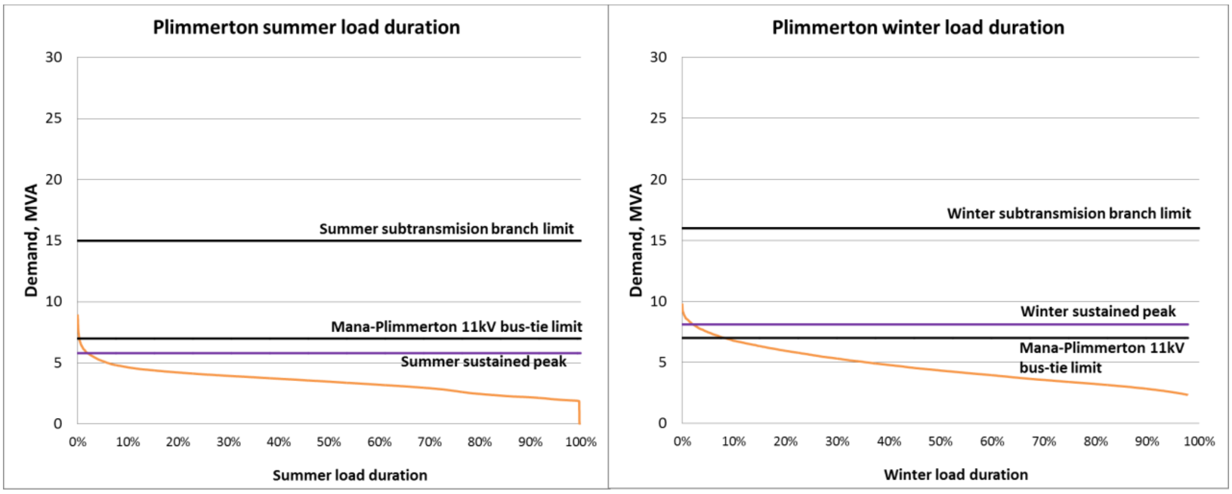


Figure 8-41 Plimmerton Load Duration

Figure 8-42 shows the forecast demand for Plimmerton zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

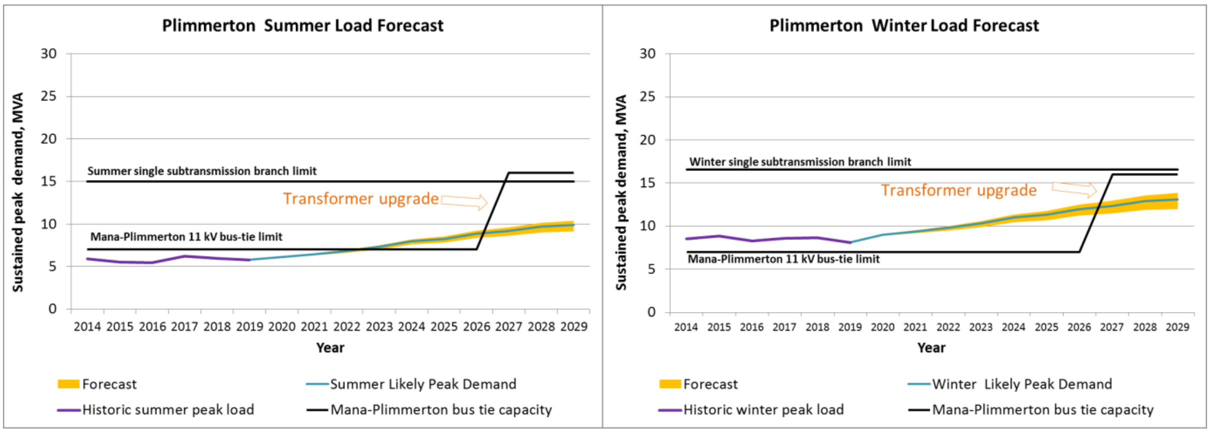


Figure 8-42 Plimmerton Load Forecast

The load forecast shows that a proportion of load is at risk in the winter periods and a summer constraint may occur if the signalled residential and small industrial development in the Plimmerton proceeds. The magnitude and timing of the risk will also be driven by the load growth due to development of residential subdivisions around Whitby. The new development will also impact the network security and available capacity at Porirua, Waitangirua zone substations and 11 kV feeders in the area.

8.5.2.6 Porirua

The peak load supplied at Porirua exceeds the N-1 subtransmission circuit branch ratings for both winter and summer periods. Following a fault on the subtransmission system, load is off-loaded from Porirua to nearby alternative zone substations.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Porirua	Winter	16.0	20.9	4.9
	Summer	14.0	15.8	1.8

Table 8-33 Current Porirua Subtransmission Constraints

The risk of increasing these constraints is dependent on planned step change demands due to re-development of the Porirua city centre, a number of residential subdivisions in the Whitby and Aotea areas and the proposed Eastern Porirua Regeneration.

Subdivisions in the Whitby and Aotea areas are likely to include 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.

Figure 8-43 shows the load duration curve against the N-1 cyclic ratings of transformer and subtransmission cable.

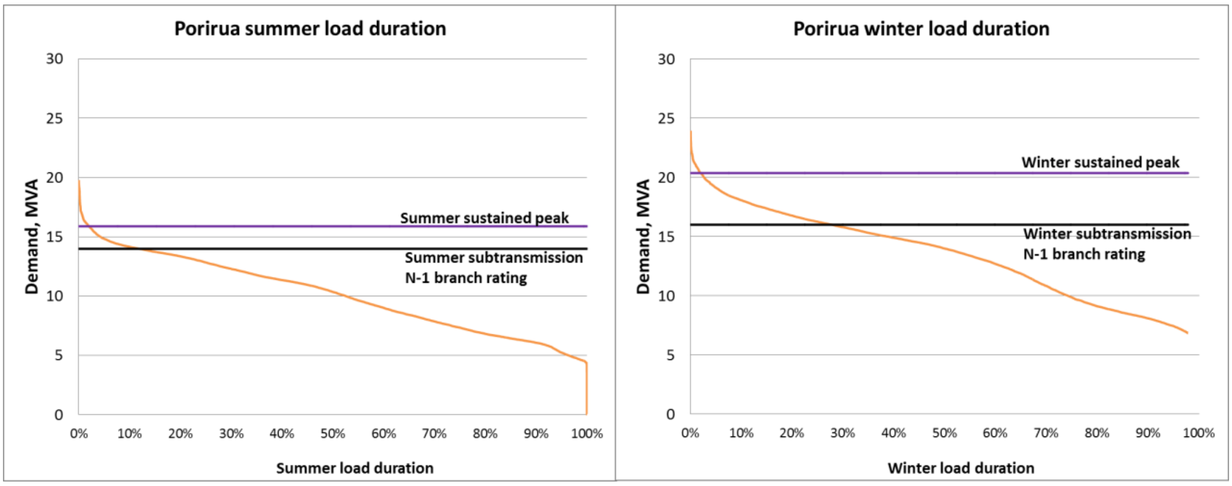


Figure 8-43 Porirua Load Duration

The load duration curve shows that at present, demand exceeds N-1 subtransmission branch rating for approximately 27.7% of the time during winter and 11.8% during summer. Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Porirua is forecast to grow as shown in Figure 8-44. The issues will be resolved with the scheduled substation upgrade project.

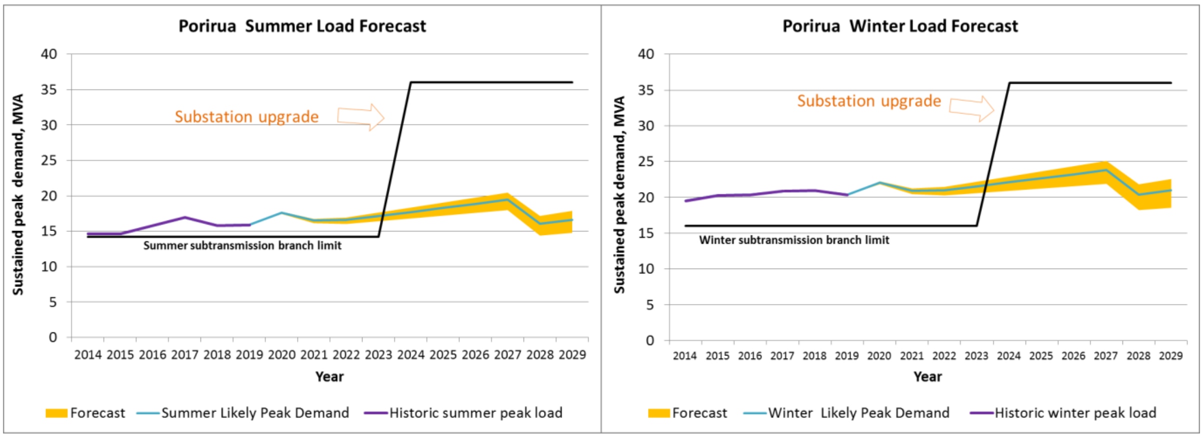


Figure 8-44 Porirua Load Forecast

8.5.2.7 Tawa

The peak load supplied at Tawa is currently within the N-1 capacity of the subtransmission circuits. Table 8-34 illustrates the seasonal constraint levels and the minimum off load requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @ 2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Tawa	Winter	16.0	14.2	0
	Summer	14.0	10.5	0

Table 8-34 Current Tawa Subtransmission Constraints

Figure 8-45 shows the load duration curve against the N-1 subtransmission branch ratings for Tawa.

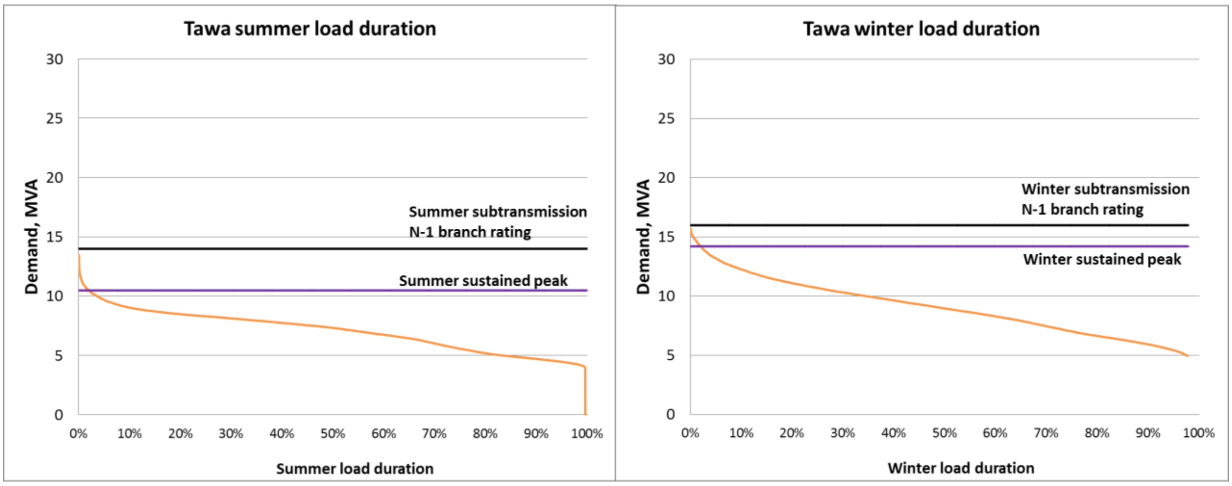


Figure 8-45 Tawa Load Duration

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Tawa is forecast to grow as shown in Figure 8-46. Without action, the peak load will exceed the N-1 subtransmission capacity from winter 2021. Most of the growth is expected to come from the Grenada North industrial area and new residential developments in Grenada.

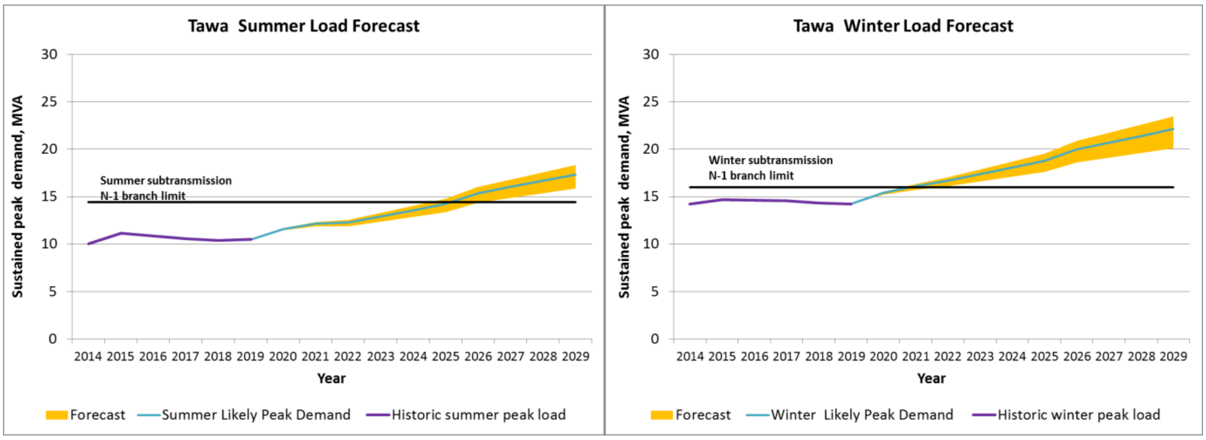


Figure 8-46 Tawa Load Forecast

8.5.2.8 Waitangirua

The sustained peak load supplied by Waitangirua is currently within the N-1 branch rating of the subtransmission circuits. Table 8-35 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Waitangirua	Winter	16.0	13.5	0
	Summer	15.2	9.6	0

Table 8-35 Current Waitangirua Subtransmission Constraints

Figure 8-47 shows the load duration curve against the N-1 subtransmission branch ratings for Waitangirua. This exceeds the network security standard for a mixed commercial and residential zone substation.

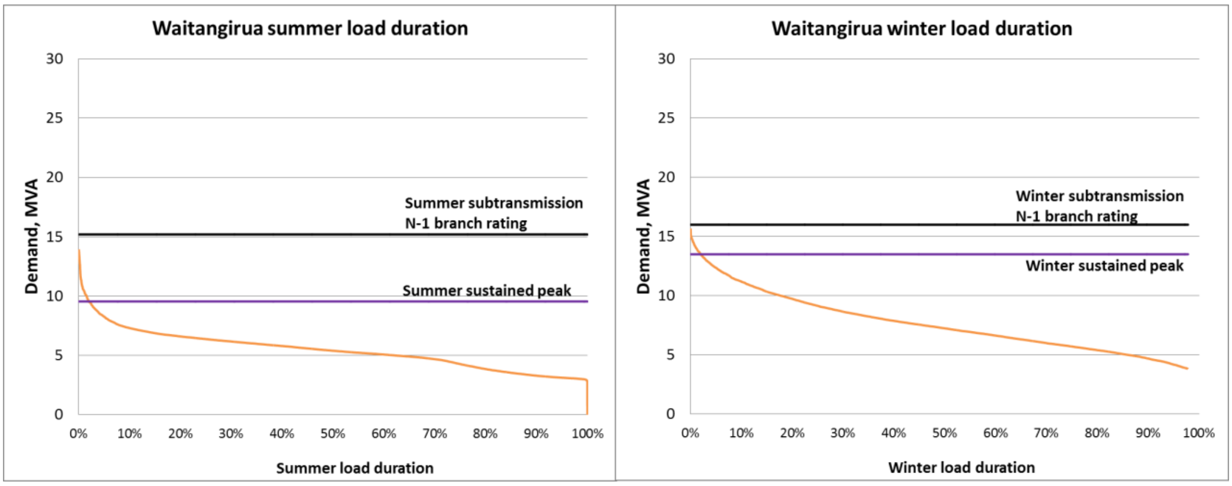


Figure 8-47 Waitangirua Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Waitangirua is forecasted to grow as show in Figure 8-48. Without action, the peak load will exceed the N-1 subtransmission capacity from 2025. Growth in the Waitangirua load is expected to come from the residential developments in Whitby area and the proposed Eastern Porirua Regeneration project.

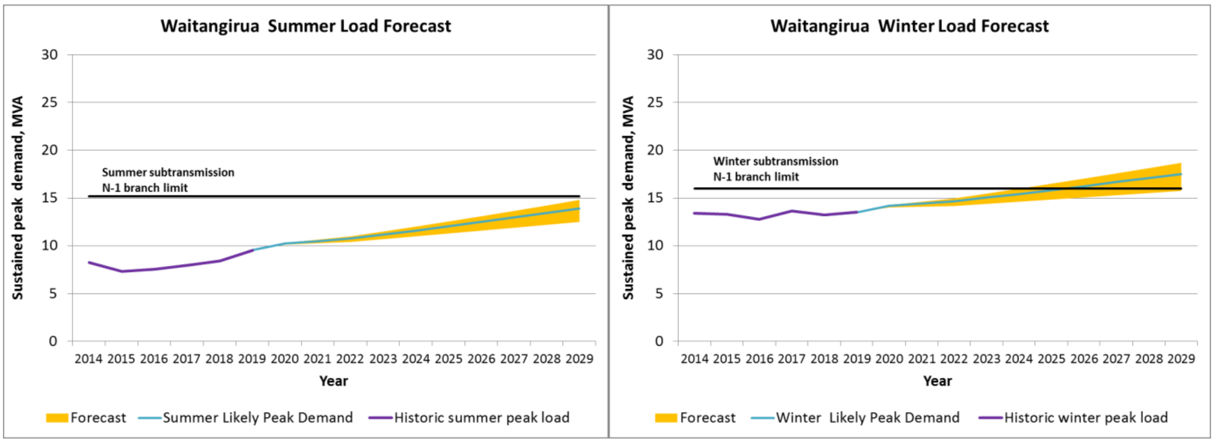


Figure 8-48 Waitangirua Load Forecast

8.5.3 Distribution Level Development Needs

The most critical distribution level issues are those associated with overload of the meshed ring feeder supplying a high number of consumers or links between zones which can be used for load transfer.

Table 8-36 below 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	Length of overloading section	Present	+5 years	Connected ICP count	Priority
Current							
JOH CB6	Radial	Johnsonville	1,392 m	80%	92%	1,731	Medium
POR CB4/5	2 Fdr Mesh	Porirua	2,284 m	62%	103%	367	Medium
POR CB06	Radial	Porirua	850 m	81%	80%	47	Medium
POR CB1/11 (POR-TIT)	2 Fdr Mesh	Porirua	8,590 m	69%	80%	3,104	High
TAW CB11	Radial	Tawa	2,207 m	69%	100%	590	Medium
WTG CB5	Radial	Waitangirua	3,582 m	76%	84%	1,679	Low
WTG CB11	Radial	Waitangirua	162 m	68%	95%	1,625	Medium
Within Five Years							
KEN CB 4	Radial	Kenepuru	493 m	Less than 67%	72%	20	Low
NGA CB 4	Radial	Ngauranga	1,024 m	Less than 67%	74%	1,651	Low
NGA CB 9	Radial	Ngauranga	755 m	Less than 67%	74%	1,008	Low
JOH CB 10	Radial	Johnsonville	383 m	Less than 67%	76%	984	Low
JOH CB 12	Radial	Johnsonville	1,177 m	Less than 67%	75%	984	Low

Table 8-36 Distribution Level Issues

Table 8-37 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 2019.

Meshed Ring	Topology	N-1 Case	Feeder	Length of overloading section	Contingency Loading	Control
POR 1/11 (POR-TIT)	2 Fdr Mesh	POR 01 out	POR 11	4,298 m	138%	Network augmentation
		POR 11 out	POR 01	4,291 m	138%	
POR 4/5	2 Fdr Mesh	POR 04 out	POR 05	591 m	102%	Network augmentation

Table 8-37 Meshed Ring Feeder Contingency Analysis

8.5.4 Summary of Network Development Plan

This section summarises the options available to meet the development needs described above.

The development options for the Northwestern Area comprise of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive because there are solutions which meet several needs for the same investment.

8.5.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions to defer investment discussed in Section 8.1.8.

8.5.4.2 Projects for 2020/21

Projects currently underway or planned to start over the next 12 months are listed in Table 8-38.

Project	Description
Porirua Incomer Cable Replacement	Replacing 11 kV cables between the power transformers and the 11 kV switchboard to lift substation capacity.
Woodman Drive – Bing Lucas link	New 11 kV distribution cable link to improve backfeed options.

Table 8-38 Northwestern Area Projects for 2020/21

8.5.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 8-39. This information is an extract from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example, many subtransmission constraints can be solved through HV distribution level configuration change or managed operationally.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Issue ID	Category	Constraint	Preferred Option	Investment Period	Investment Amount (M)
B1I1	SUBT	NGA subtransmission future configuration	Replace the existing TKR KDH line supplying Ngauranga with a 33 kV pole line following the same route	2024	$0.3
B1I2	SUBT	JOH 33/11 kV transformer capacity	Upgrade NGA transformer capacity (replace existing with PAL removed 24 MVA units) and transfer some of JOH load to NGA	2026	$2
B1I3	SUBT	JOH 33 kV subtransmission capacity	Develop Grenada North Zone (GRN) ZS supplied from first TKR-KDH line section. Upgrade 11 kV ties to supply NGA and JOH from GRN.	2027-2030	$20
B1I4	DIST	JOH 6 feeder capacity	Same as B1I2	2027-2030	$0
B1I5	SUBT	TAW 33/11 kV transformer capacity	Same as B1I3	2027-2030	$0
B1I6	DIST	TAW 11 feeder capacity	Same as B1I3	2027-2030	$0
B1I7	SUBT	NGA 33/11 kV transformer capacity	Same as B1I2	2027-2030	$0
B2I1	SUBT	KEN 33kV subtransmission capacity	Transfer load to adjacent POR ZS after more capacity is created at POR	2025	$0
B2I2	SUBT	POR 33/11kV transformer capacity	A complete upgrade of the POR 33 kV Cable, ZS TX and switchboard, for 36 MVA	2022-2025	$16
B2I3	SUBT	POR 33kV subtransmission capacity	Same as B2I2	2022-2025	$0
B2I4	DIST	POR 4/5 ring feeder capacity	Add a new feeder to the ring as part of the POR ZS upgrade, extend about 0.9 km of feeder to form a three feeder ring.	2023	$1.4
B2I5	DIST	POR 6 feeder capacity	Transfer some of the load to KEN09 and/or new feeder(s) from KEN. After POR4/5 feeder upgrade, install extra CB at 19 Parumoana to split the existing POR6 into two separate feeders	2025	$0.3
B2I6	SUBT	POR 1/11 (TIT) ring feeder capacity	Feeder Upgrade, cross harbour link from TIT 3 to POR2	2023	$3
B2I7	SUBT	WTG 33/11 kV transformer capacity	Same as B2I2	2022-25	$0
B2I8	SUBT	WTG 33 kV subtransmission capacity	Same as B2I2	2022-25	$0
B2I9	DIST	WTG 5 feeder capacity	Transfer load to adjacent feeders (WTG 3)	2026	$1.4
B2I10	DIST	WTG 11 feeder capacity	After completing POR upgrade with spare capacity created, install new ties near Adventure drive on WTG11.	2026	$1.8
B3I1	SUBT	TIT supply security on non - transferable load	Same as B2I6	2023	$0
B3I2	SUBT	PLI supply capacity	Install a 33 kV bus, a second 24 MVA transformer and a second 11kV bus section at PLI.	2026-2027	$8
B3I3	SUBT	MAN supply capacity	Reinforce 11 kV feeders to enable load transfer from MAN to POR and PLI after their upgrade.	2030	$4

Table 8-39 Northwestern Area Development Summary

8.6 Northeastern Area NDRP

This section provides a summary of the Northeastern Area NDRP.

8.6.1 GXP Development Plan

The Northeastern area is supplied from four GXPs. Gracefield and Upper Hutt provide subtransmission supply at 33 kV, while Melling and Haywards GXPs provide supply at 33 kV and 11 kV. The transformer capacity and the maximum system demand are set out in Table 8-40.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Maximum Demand (MVA)	
			2019	2029
Gracefield 33 kV	1*85+1*60	60 / 60	55.0	60.6
Upper Hutt 33 kV	2x 40	51 / 53	26.6	27.5
Melling 33 kV	2x 50	54 / 55	28.5	28.7
Melling 11 kV	2x 25	28 / 28	23.0	29.2
Haywards 33 kV	2 x 30	36 / 36	15.3	16.7
Haywards 11 kV	2x 30	36 / 36	16.3	16.6
Total (after diversity)	-	-	**165**	**179**

Table 8-40 Northeastern Area GXP Capacities

8.6.1.1 Gracefield

There were two identical transformers at Gracefield which provide 33 kV supply to four WELL zone substations (Wainuiomata, Gracefield, Seaview and Korokoro). In November 2019, one of the transformers experienced a catastrophic failure and was removed out of service. In December 2019, Transpower commissioned one of its national strategic spare transformers in Gracefield. WELL will work with Transpower on the transformer replacement plan and ensure the transition risk is minimised in relation to this project.

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.

8.6.1.2 Haywards

There are two parallel 110/33/11 kV, three-winding, 60/30/30 MVA transformers at Haywards that provide N-1 supply to:

- Trentham zone substation via two 33 kV circuits, and
- Haywards 11kV switch board.

The two new transformers were commissioned in 2019. This provides full N-1 security to the 11kV bus.

8.6.1.3 Upper Hutt

There are two 110/33 kV transformers at Upper Hutt GXP, supplying a 33 kV bus that feeds zone substations at Brown Owl and Maidstone.

WELL recently installed new RTUs at Brown Owl and Maidstone. An upgrade project on the subtransmission protection system is scheduled in 2020. The new protection equipment will be designed to interface with Transpower equipment at the site.

8.6.1.4 Melling

The Melling GXP comprises two parallel 110/33 kV transformers, supplying a 33 kV switchboard that feeds the zone substations of Waterloo and Naenae. A separate 11 kV switchboard is supplied by two 110/11 kV transformers.

The capacity of the 110/11 kV transformers is restricted due to the limit imposed by the protection equipment. Transpower propose to resolve this protection limitation to increase the cyclic capacity of the transformers. In the meantime, WELL will work with Transpower to manage network loading risk using demand side management and operational control.

8.6.2 Subtransmission Network Development Needs

This section describes the identified security of supply constraints and development needs for the Northeastern Area.

The Northeastern network consists of 18 subtransmission 33 kV circuits supplying nine zone substations. Each zone substation supplies the respective 11 kV distribution network with inter-connectivity via switched open points to adjacent zones. The Haywards and Melling GXP 11 kV switchboards directly feed into the distribution network. The characteristics of each zone substation are listed in Table 8-41.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)	Constraining Branch Component	Sustained Peak Demand (MVA)		Date Constraints are Binding	ICP Counts as at 2019
				2019	2029		
Existing constraints							
Korokoro	Winter	15.5	33kV cable	18.4	16.0	Existing	3,801
	Summer	13.2	33kV cable	15.0	11.1		
Seaview	Winter	13.8	33kV cable	17.2	20.0	Existing	3,461
	Summer	10.6	33kV cable	12.1	14.0		
Wainuiomata	Winter	16.5	33/11kV transformer	16.5	22.0	Existing	6,890
	Summer	12.1	33kV cable	11.4	16.2		
Maidstone	Winter	17.6	33kV cable	14.5	16.0	Existing (Summer)	4,768
	Summer	10.2	33kV cable	10.8	13.1		

Forecasted constraints							
Waterloo	Winter	20.0	33kV cable	17.0	16.0	2022	5,814
	Summer	12.0	33kV cable	11.6	12.6		
Not Constrained							
Brown Owl	Winter	18.4	33/11kV transformer	14.7	15.0	Not Constrained	6,434
	Summer	12.9	33kV cable	9.8	11.4		
Gracefield	Winter	16.5	33kV cable	11.7	12.0	Not Constrained	2,621
	Summer	12.0	33kV cable	8.6	8.3		
Naenae	Winter	18.3	33kV cable	14.7	15.0	Not Constrained	6,147
	Summer	13.9	33kV cable	10.2	10.4		
Trentham	Winter	19.1	33kV cable	14.5	17.0	Not Constrained	5,275
	Summer	14.7	33kV cable	10.2	13.7		

Table 8-41 Northeastern Area Zone Substation Capacities

8.6.2.1 Brown Owl

The sustained peak demand supplied by Brown Owl is currently within the N-1 capacity of the zone substation. Table 8-42 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Subtransmission N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Brown Owl	Winter	18.4	14.7	0
	Summer	12.9	9.8	0

Table 8-42 Current Brown Owl Subtransmission Constraints

Figure 8-49 shows the load duration curve against the N-1 branch ratings of the subtransmission for Brown Owl. The load duration curve shows that at present the demand exceeds the firm capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

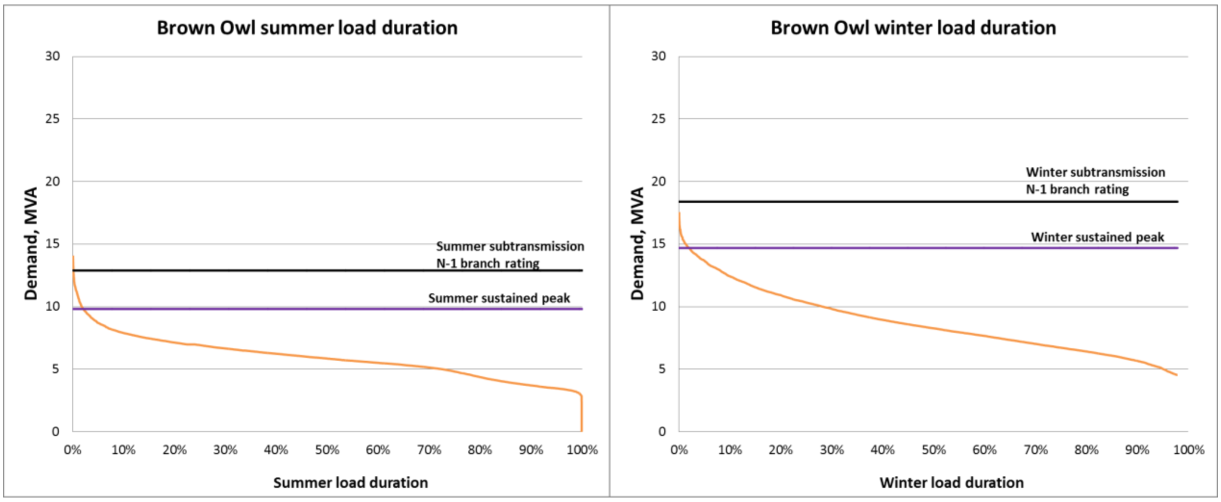


Figure 8-49 Brown Owl Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Brown Owl is forecasted to grow as show in Figure 8-50.

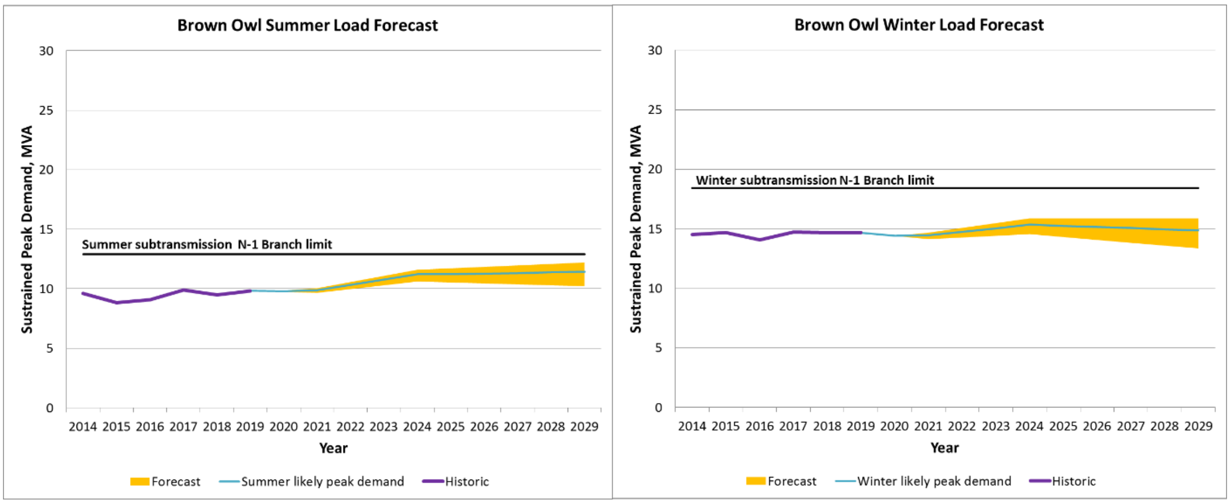


Figure 8-50 Brown Owl Load Forecast

8.6.2.2 Gracefield

The sustained peak demand supplied by Gracefield is currently within the N-1 capacity of the subtransmission circuits. Table 8-43 illustrates the seasonal constraint levels and the minimum off load requirements. The 2019 winter peak was affected by load transferred to Seaview and Waterloo to enable the Gracefield switchboard replacement. Now that that project is complete, Gracefield load is expected to return to its normal range.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Gracefield	Winter	16.5	8.6*	0
	Summer	12.0	8.6	0

Table 8-43 Current Gracefield Subtransmission Constraints

Figure 8-51 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Gracefield. The load duration curve shows that at present the demand is below the firm capacity at the zone substation.

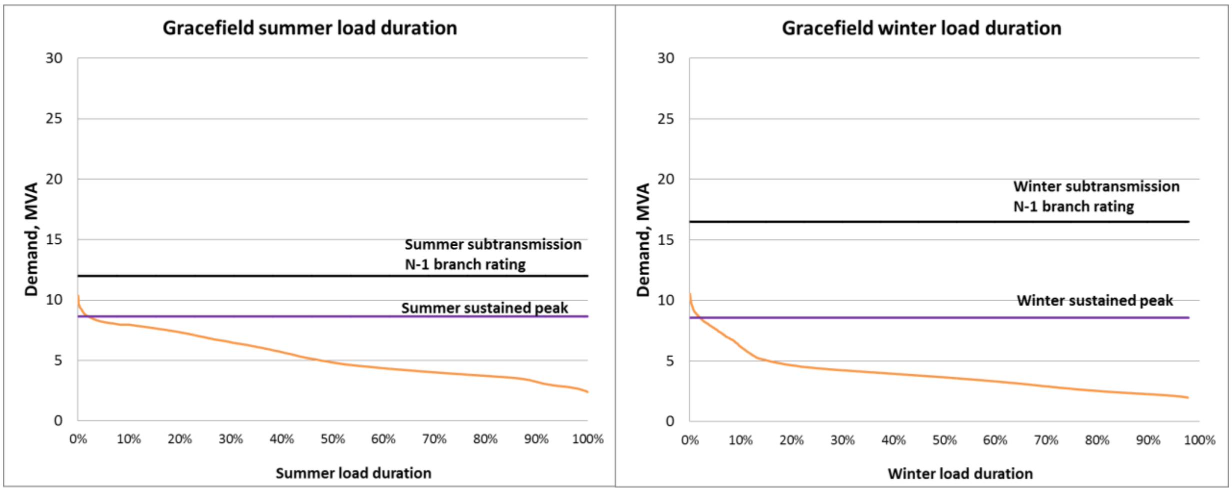


Figure 8-51 Gracefield Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Gracefield is forecasted to grow as show in Figure 8-52. The subtransmission capacity constraints are plotted for comparison.

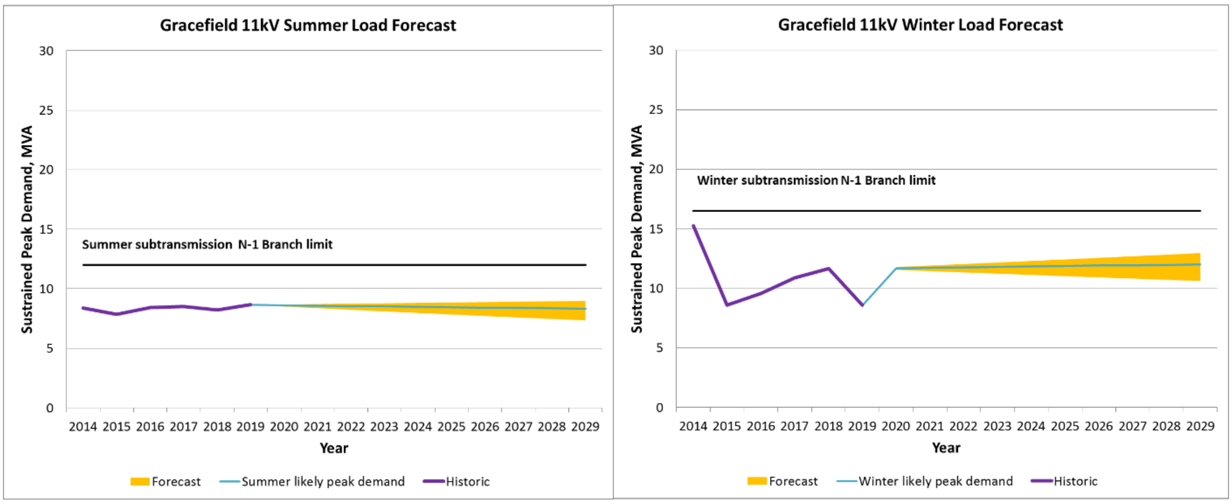


Figure 8-52 Gracefield Load Forecast

8.6.2.3 Haywards

The sustained peak demand supplied by Haywards is currently within the N-1 capacity of subtransmission circuits. Table 8-44 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Haywards	Winter	36	16.2	0
	Summer	36	11.1	0

Table 8-44 Current Haywards Subtransmission Constraints

Figure 8-53 shows the load duration curve against the N-1 branch ratings of the subtransmission cables for Haywards. The load duration curve shows that at present the demand is below the firm capacity at the zone substation. This is within the network security standard for a mixed commercial and residential zone substation.

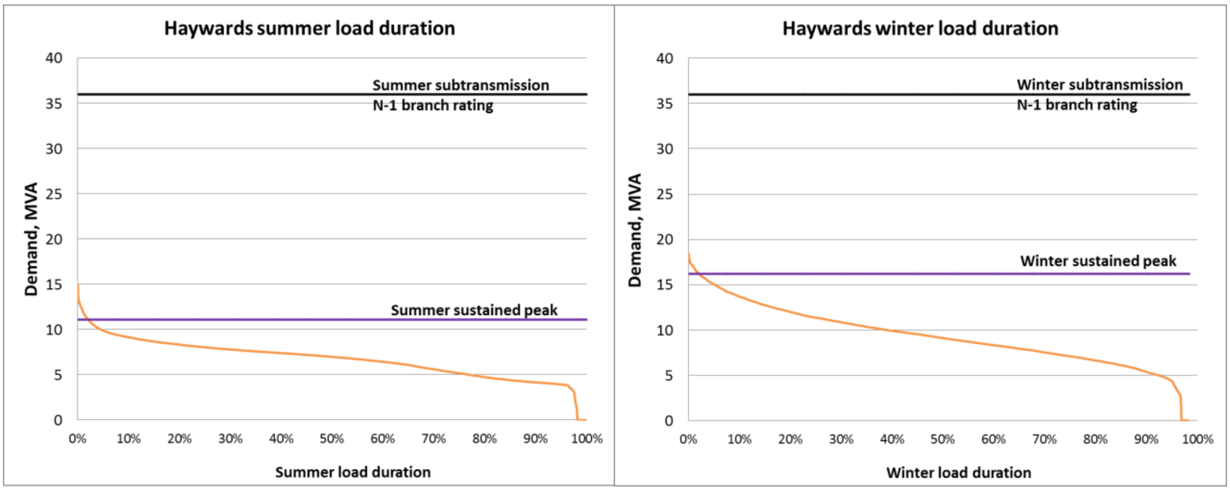


Figure 8-53 Haywards Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Haywards is forecasted to grow as show in Figure 8-54. The subtransmission capacity constraints are plotted for comparison.

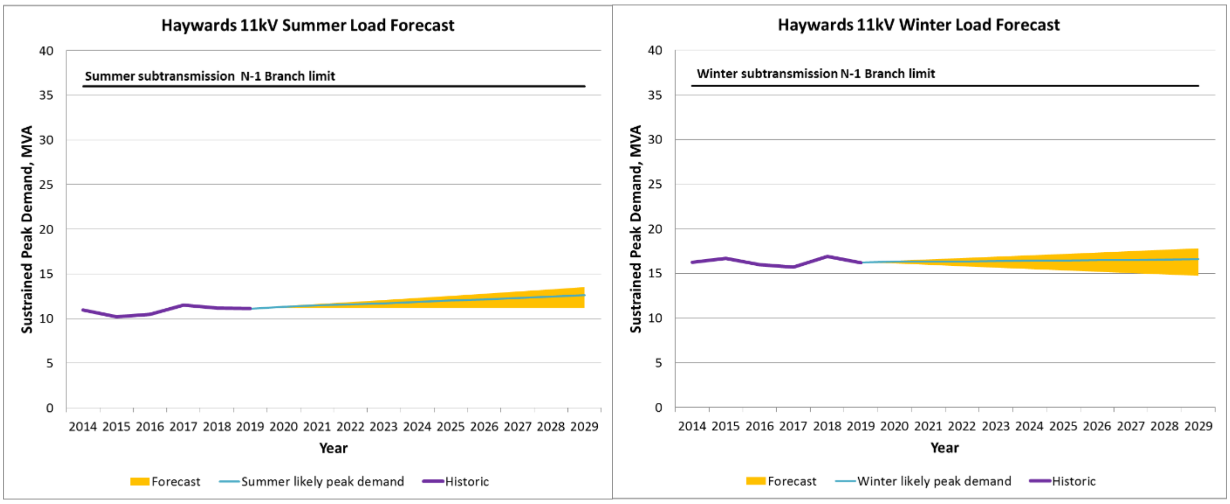


Figure 8-54 Haywards Load Forecast

8.6.2.4 Korokoro

The sustained peak load at Korokoro currently exceeds the N-1 capacity of subtransmission circuits. Table 8-45 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Korokoro	Winter	15.5	18.4	2.8
	Summer	13.2	15.0	1.8

Table 8-45 Current Korokoro Subtransmission Constraints

Figure 8-55 shows the load duration curve against the N-1 ratings of transformer and subtransmission cables for Korokoro. The load duration curve shows that at present the demand exceeds the summer firm capacity by approximately 24% of the time over the summer period and the winter firm capacity approximately 20% of the time over the winter period. This analysis uses a load duration curve based on 30 minute periods and is higher than the sustained peak.

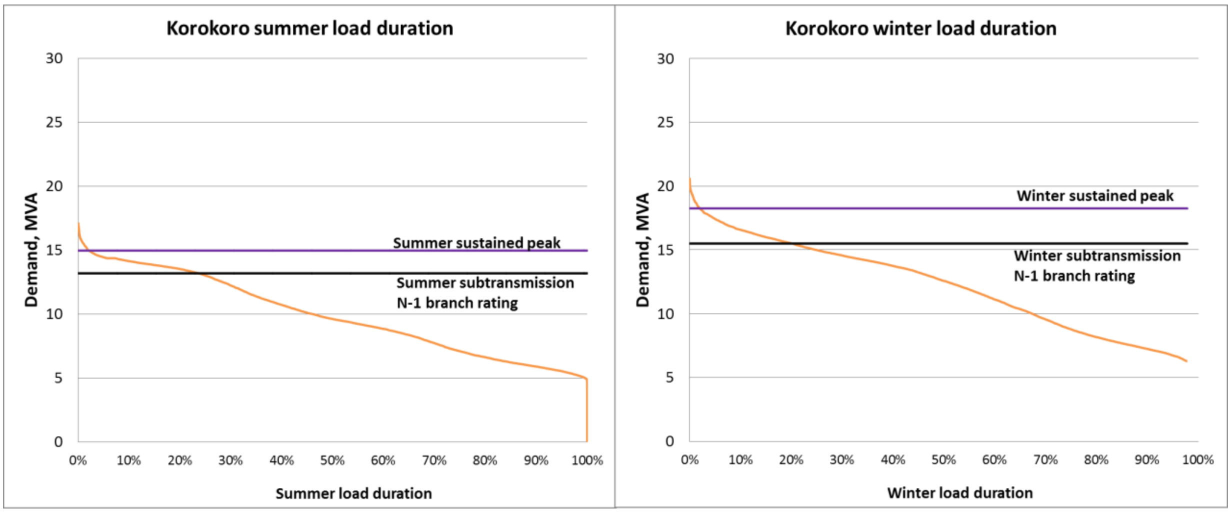


Figure 8-55 Korokoro Load Duration

Based on the estimated growth scenarios and development within the planning period, the sustained peak load at Korokoro is forecasted as shown in Figure 8-56. The subtransmission capacity constraints are plotted for comparison.

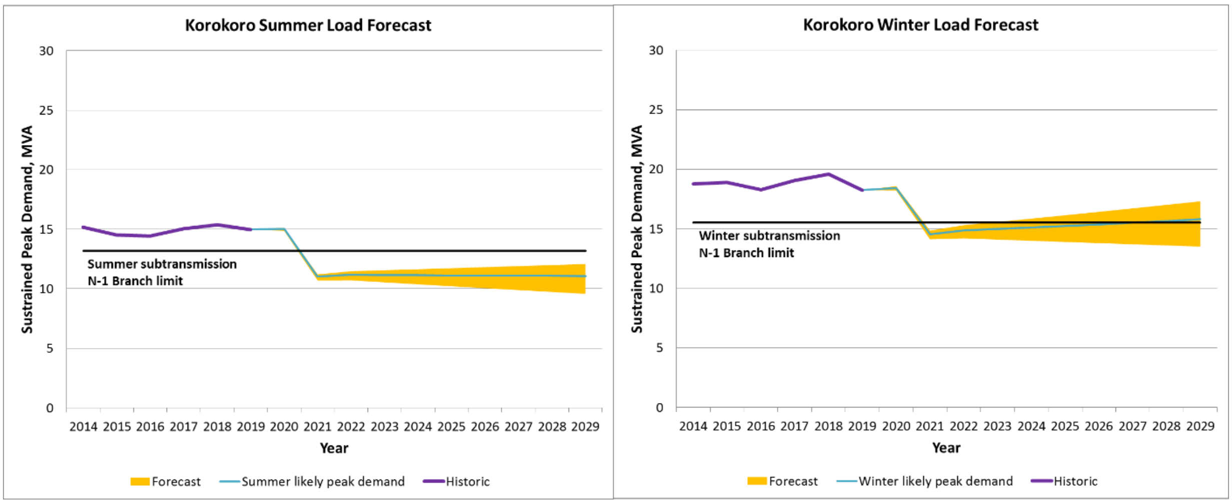


Figure 8-56 Korokoro Load Forecast

WELL proposes to transfer some load from the Korokoro zone substation to the Melling zone substation in 2021. This will reduce the forecast load at Korokoro zone substation to within the N-1 subtransmission capacity for the forecast period.

WELL will continue monitoring load growth and manage the overloading risk through operational control.

8.6.2.5 Maidstone

The sustained peak demand supplied by Maidstone currently exceeds the N-1 capacity of subtransmission circuits in summer. Table 8-46 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Maidstone	Winter	17.6	14.5	0
	Summer	10.2	10.8	0.6

Table 8-46 Current Maidstone Subtransmission Constraints

Figure 8-57 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Maidstone. The load duration curve shows that at present the demand exceeds the summer N-1 capacity for approximately 3% of the time over the summer period.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

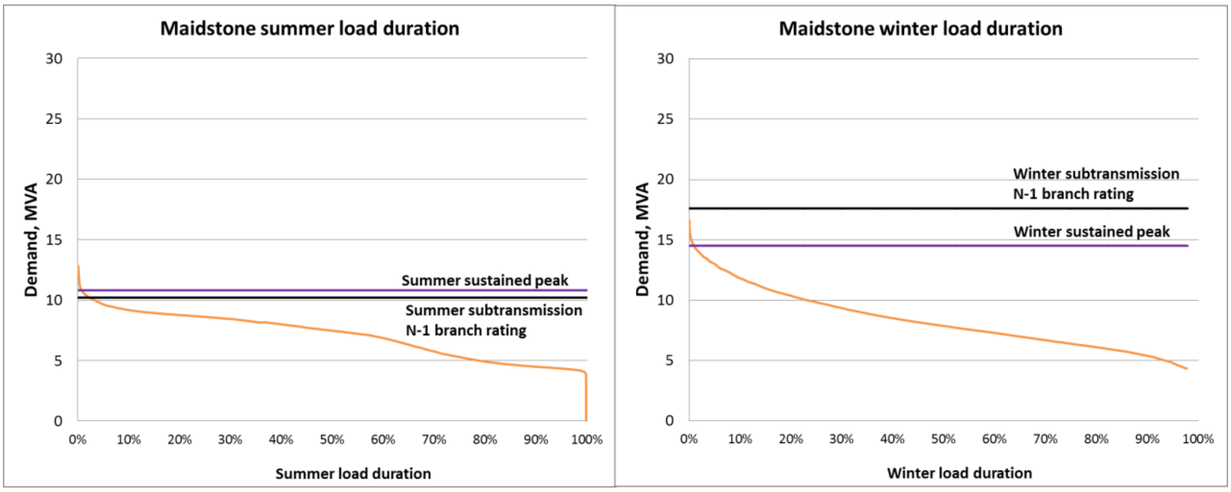


Figure 8-57 Maidstone Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Maidstone is forecasted to grow as show in Figure 8-58.

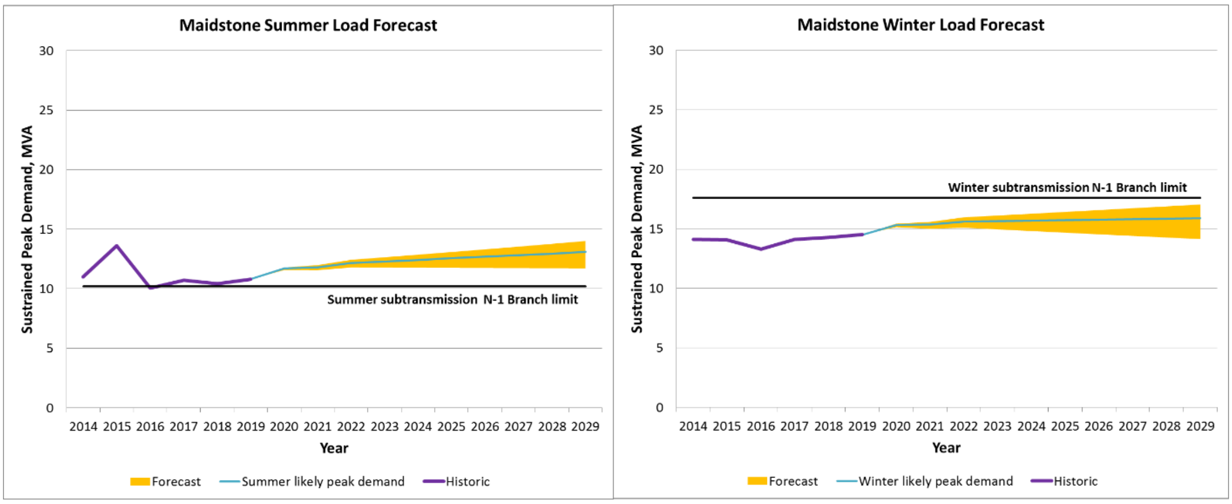


Figure 8-58 Maidstone Load Forecast

8.6.2.6 Melling

The sustained peak demand supplied by Melling is currently within the N-1 capacity of subtransmission circuits. Table 8-47 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Melling	Winter	28	23.0	0
	Summer	28	17.7	0

Table 8-47 Current Melling Subtransmission Constraints

Figure 8-59 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Melling. The load duration curve shows that at present the demand exceeds the N-1 capacity less than 2%

of the year. This is within the network security standard for a mixed commercial and residential zone substation.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

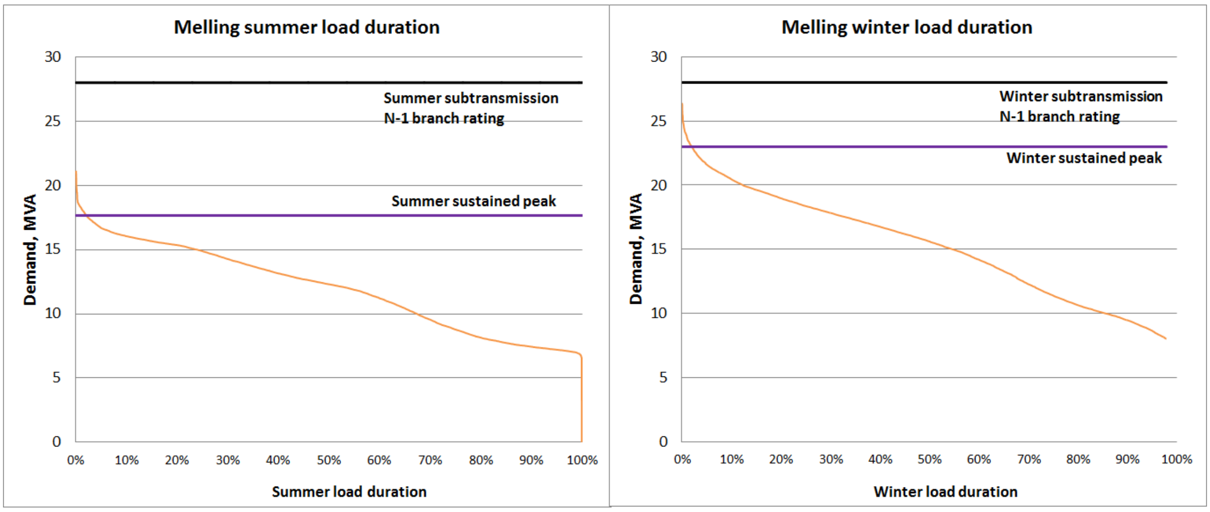


Figure 8-59 Melling Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Melling is forecasted to grow as show in Figure 8-60.

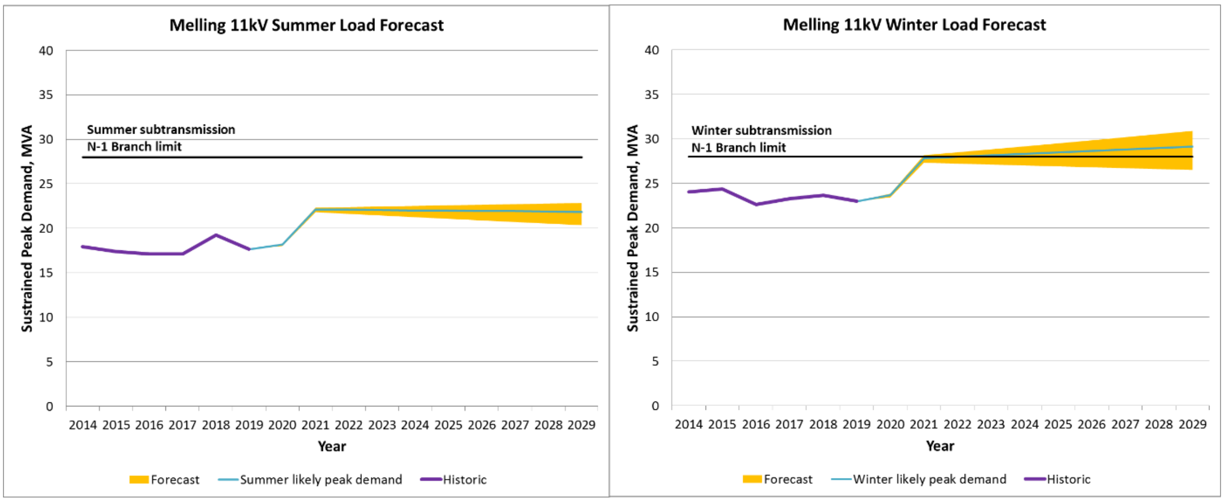


Figure 8-60 Melling Load Forecast

WELL proposes to relieve the loading on the Korokoro zone substation by transferring some load to the Melling zone substation in 2021. This will increase the forecast winter load at the Melling zone substation to approximately the N-1 subtransmission capacity within the forecast period. WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

8.6.2.7 Naenae

The sustained peak demand supplied by Naenae is currently within the N-1 capacity of the subtransmission circuits. Table 8-48 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Naenae	Winter	18.3	14.7	0
	Summer	13.9	10.2	0

Table 8-48 Current Naenae Subtransmission Constraints

Figure 8-61 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Naenae. The load duration curve shows that at present the demand exceeds the firm capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

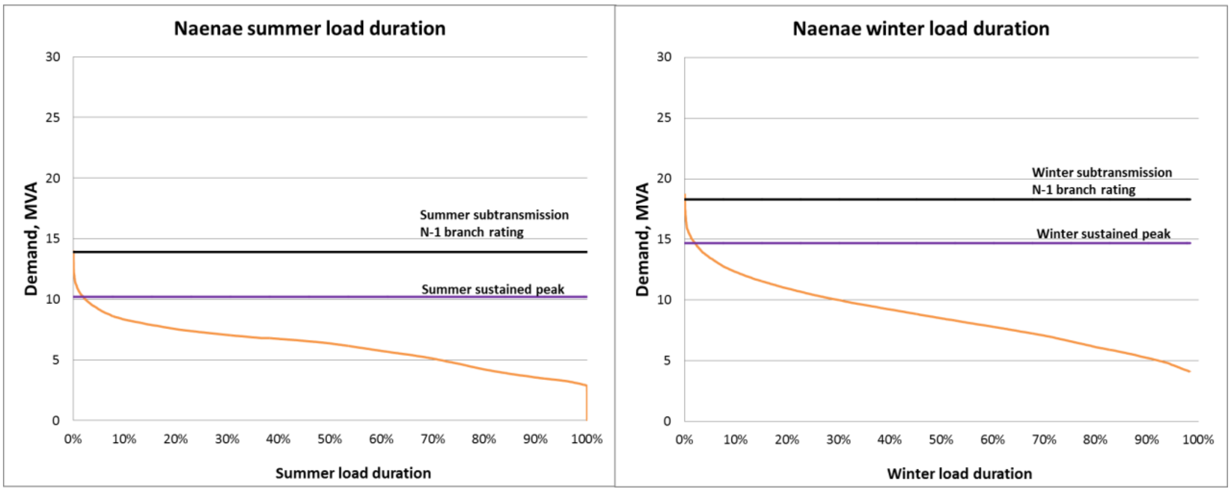


Figure 8-61 Naenae Load Duration

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Naenae is forecasted to grow as show in Figure 8-62.

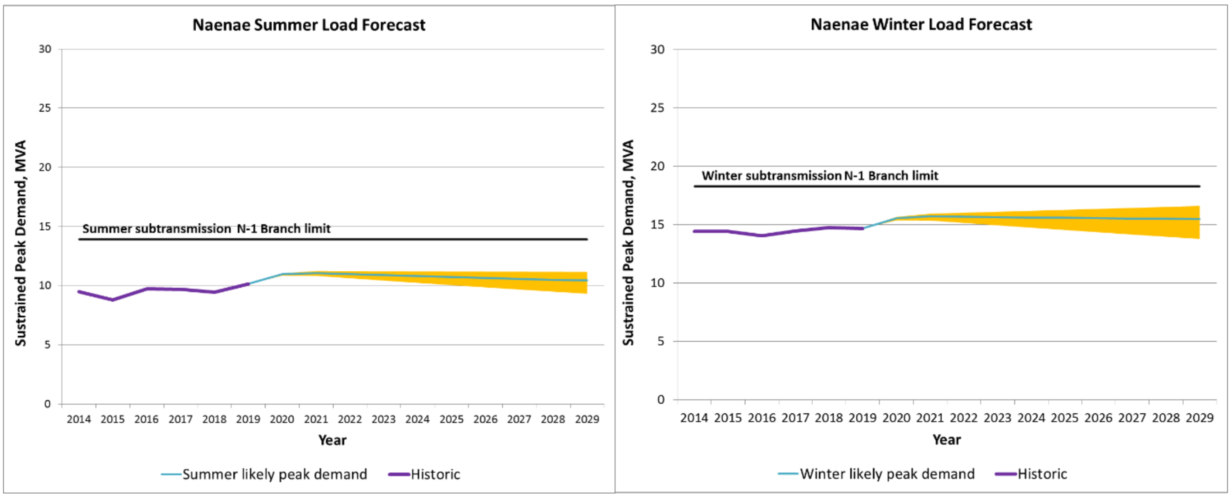


Figure 8-62 Naenae Load Forecast

8.6.2.8 Seaview

The sustained peak demand supplied by Seaview currently exceeds the summer and winter N-1 capacity of the subtransmission circuits. Table 8-49 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Seaview	Winter	13.8	17.2	3.4
	Summer	10.6	12.1	1.5

Table 8-49 Current Seaview Subtransmission Constraints

Figure 8-63 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Seaview. The load duration curve shows that at present the demand exceeds the summer firm capacity by approximately 17% of the time over the summer period and winter firm capacity by approximately 23% of the of the time over the winter period. The large step change of the winter load in Seaview was due to load shift from Gracefield to enable the Gracefield 11 kV switchboard upgrade project. Now that that project is complete, Seaview load is expected to return to its normal range.

WELL will investigate potential options to relieve this constraint. In the meantime, we will monitor load growth and manage the overloading risk by shifting open points on the 11 kV feeders and through operational control.

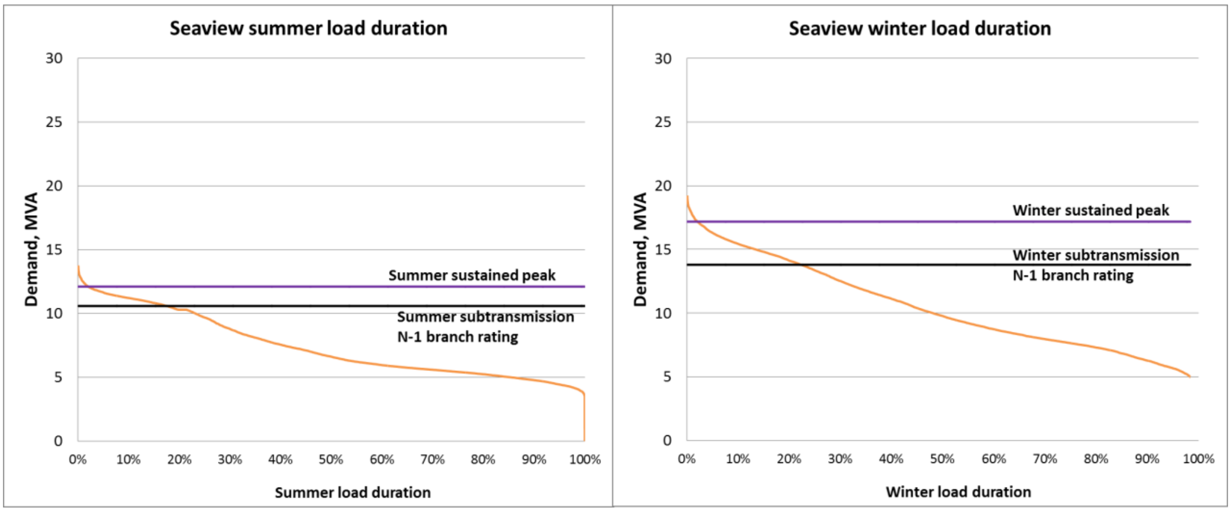
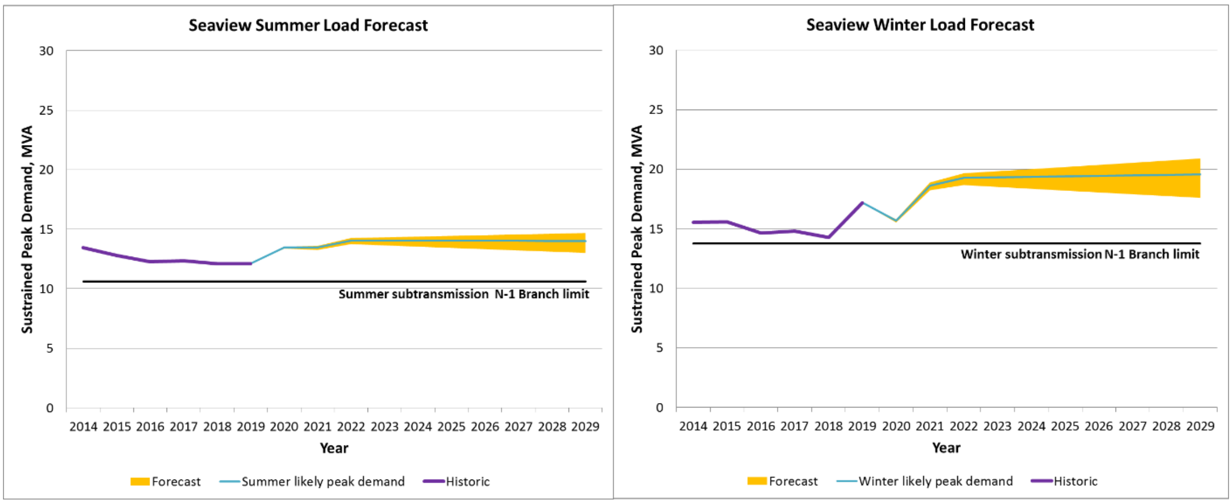


Figure 8-63 Seaview Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Seaview is forecasted to grow as show in Figure 8-64. A significant increase in the forecast load growth shown is expected to come from proposed industrial development between 2020 and 2022 and would require additional load to be moved to Gracefield.



Note: 2019 winter peak includes load transferred from Gracefield to enable the Gracefield switchboard replacement

Figure 8-64 Seaview Load Forecast

8.6.2.9 Trentham

The sustained peak demand supplied by Trentham is currently within the N-1 capacity of the subtransmission circuits. Table 8-50 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Trentham	Winter	19.1	14.5	0
	Summer	14.7	10.2	0

Table 8-50 Current Trentham Subtransmission Constraints

Figure 8-65 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Trentham. The load duration curve shows that at present the demand is below the firm capacity at the zone substation. This is within the network security standard for a mixed commercial and residential zone substation.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

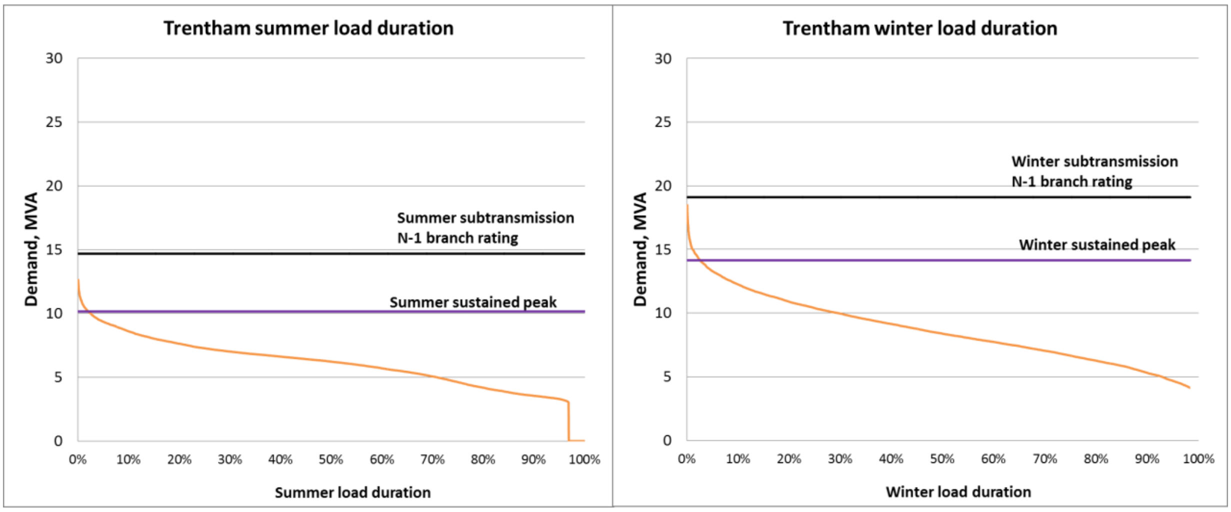


Figure 8-65 Trentham Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Trentham is forecasted to grow as show in Figure 8-66. The forecast load growth could come from proposed residential sub-divisions and commercial developments in the area.

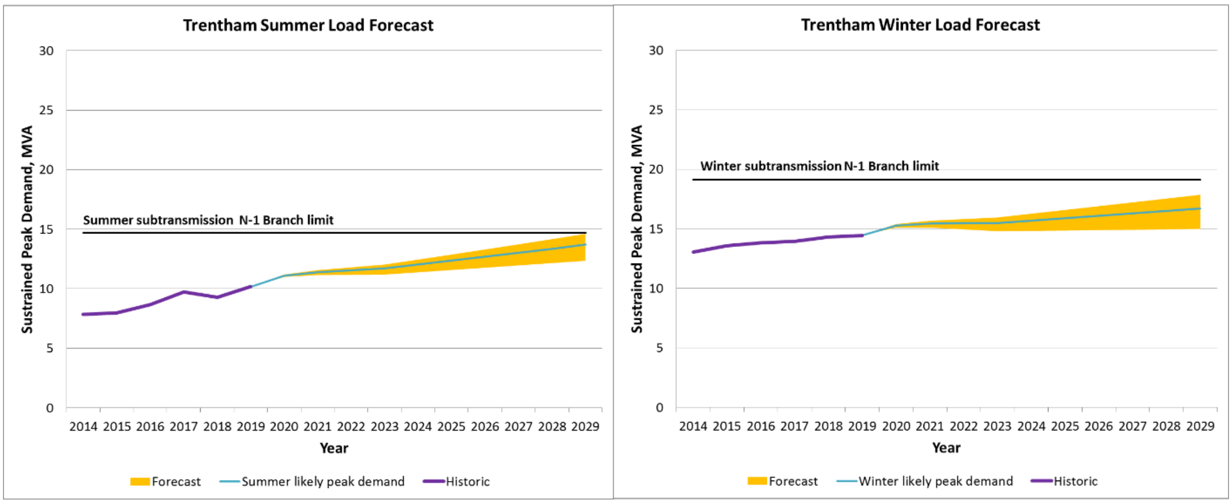


Figure 8-66 Trentham Load Forecast

8.6.2.10 Wainuiomata

The sustained peak demand supplied by Wainuiomata currently matches the winter N-1 capacity of the subtransmission circuits. Table 8-51 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Wainuiomata	Winter	16.5	16.5	0
	Summer	12.1	11.4	0

Table 8-51 Current Wainuiomata Subtransmission Constraints

Figure 8-67 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Wainuiomata. The load duration curve shows that at present the demand exceeds the firm capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

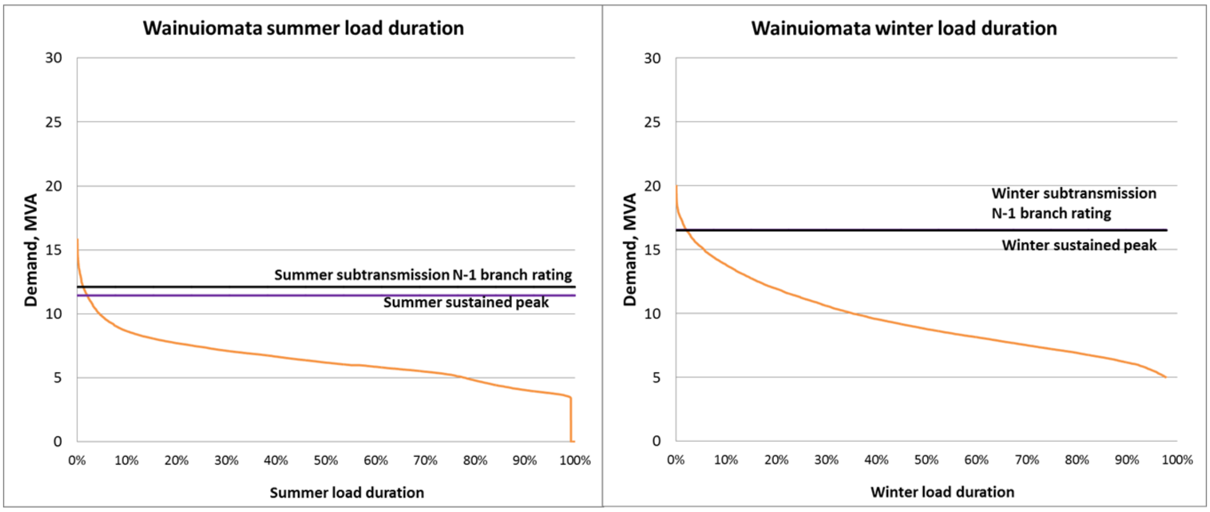


Figure 8-67 Wainuiomata Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Wainuiomata is forecasted to grow as show in Figure 8-68. The forecast load growth could come from proposed residential sub-divisions and commercial developments in the area. The limiting component is the cable constraint which is relatively simple to fix due to the short cable lengths.

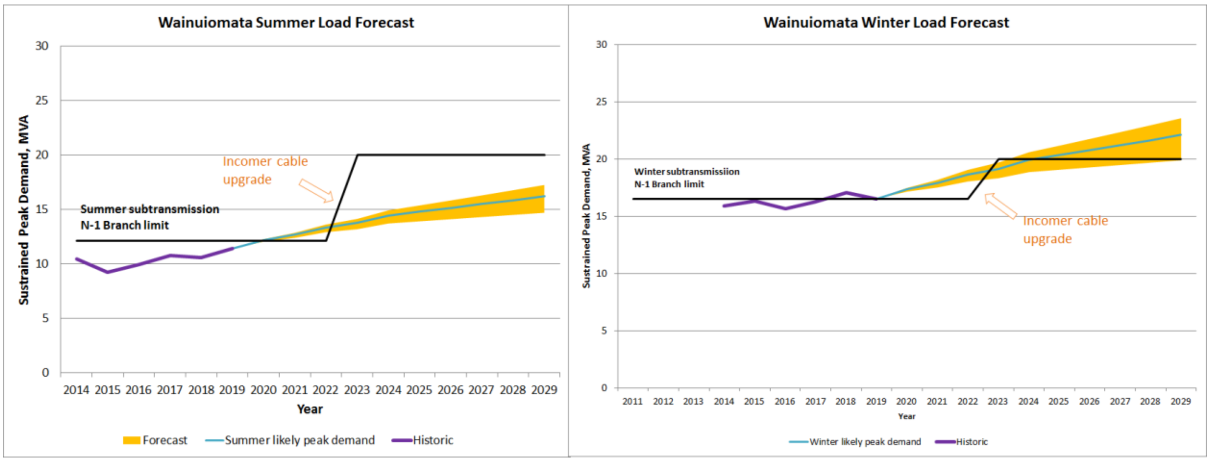


Figure 8-68 Wainuiomata Load Forecast

8.6.2.11 Waterloo

The sustained peak demand supplied by Waterloo is currently within the N-1 capacity of the subtransmission. Table 8-52 illustrates the seasonal constraint levels and the minimum off load requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Sustained Peak Demand @2019 (MVA)	Minimum off load for N-1 @ peak (MVA)
Waterloo	Winter	20.1	17.0	0
	Summer	12.0	11.6	0

Table 8-52 Current Waterloo Subtransmission Constraints

Figure 8-69 shows the load duration curve against the N-1 branch ratings of the subtransmission circuits for Waterloo. The load duration curve shows that at present the demand exceeds the firm capacity less than 2% of the year. This is within the network security standard for a mixed commercial and residential zone substation.

WELL will monitor load growth and manage the overloading risk by shifting open points on the HV feeders and through operational control.

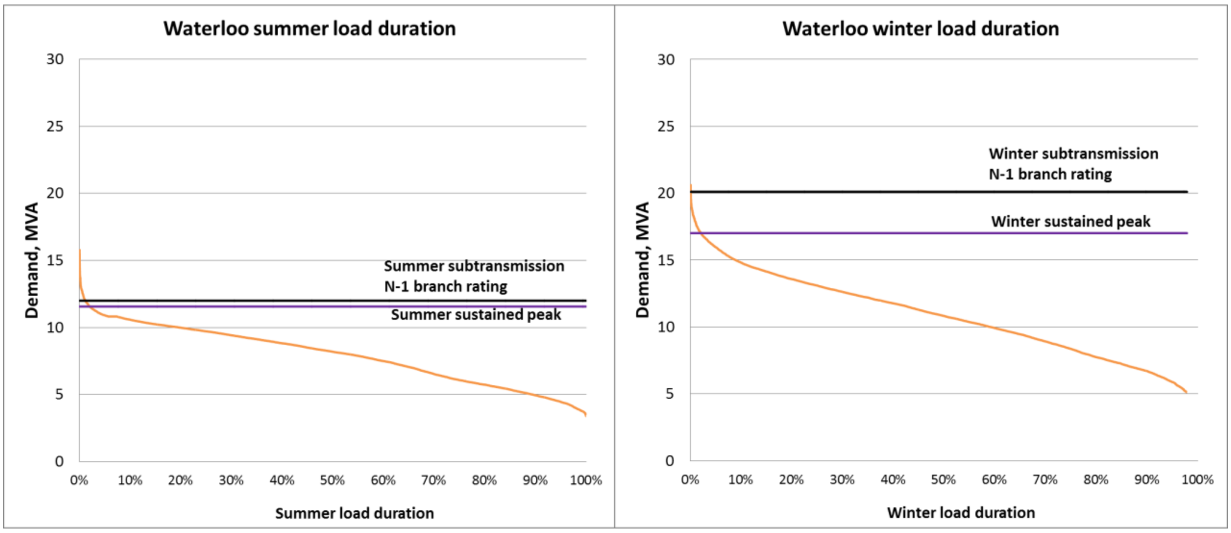
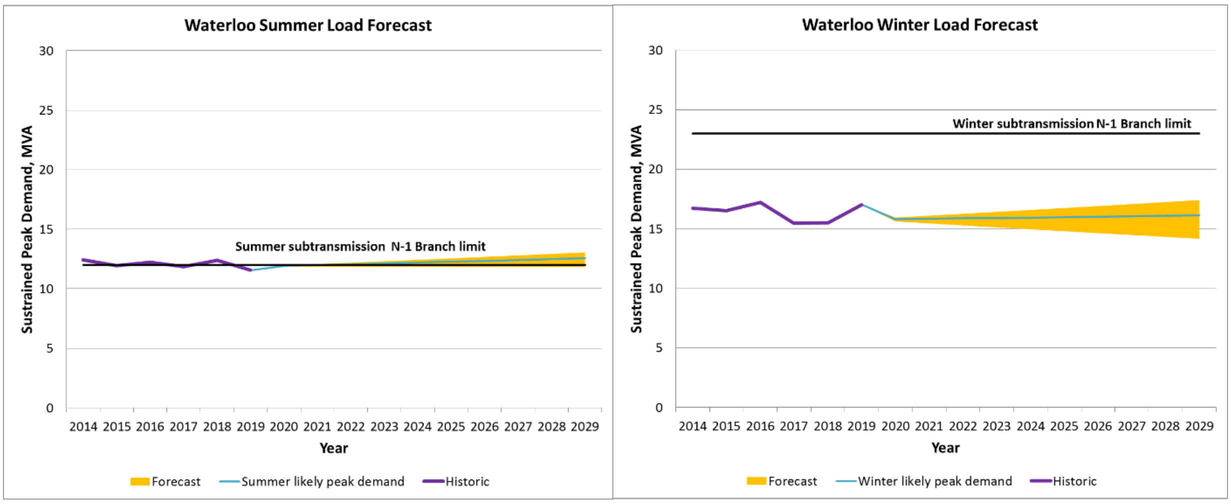


Figure 8-69 Waterloo Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Waterloo is forecasted to grow as show in Figure 8-70.



2019 winter peak includes load transferred from Gracefield to enable the Gracefield switchboard replacement

Figure 8-70 Waterloo Load Forecast

8.6.3 Distribution Level Development Needs

The most critical distribution level issues are those associated with overload radial feeders supplying critical loads. Table 8-53 shows where the applicable security criteria for the various feeder configurations are breached and an estimation of when the constraints bind.

Feeder	Topology	Zone Substation	Length of overloading section	Present	+5 years	Feeder ICP Count	Priority
Current							
BRO CB8	Radial	Brown Owl	697 m	73%	76%	1,479	Low
HAY CB2722	Radial	Haywards (GXP)	3,342 m	73%	82%	1,581	Medium
WAT CB5	Radial	Waterloo	326 m	70%	80%	1,722	Medium
WAT CB9	Radial	Waterloo	321 m	90%	102%	295	Low (due to GRA project offload)
Within 5 Years							
MEL CB5	Radial	Melling	1,673 m	Less than 67%	76%	248	Low
MEL CB11	Radial	Melling	2,539 m	Less than 67%	113%	497	Medium
WAT CB13	Radial	Waterloo	312 m	Less than 67%	72%	1,218	Low
SEA CB3	Radial	Seaview	564 m	Less than 67%	72%	706	Low
SEA CB6	Radial	Seaview	389 m	Less than 67%	84%	161	Low
WNU CB6	Radial	Wainuiomata	871 m	Less than 67%	72%	1,417	Low
WNU CB13	Radial	Wainuiomata	608 m	Less than 67%	73%	1,042	Medium

Table 8-53 Distribution Level Issues

The identified highly loaded feeders supplied from Maidstone, Waterloo and Haywards are forecast to decline in load over the planning period and may not require mitigation.

There is no contingency analysis is this region as there are no ring feeders.

8.6.4 Summary of Network Development Plan

This section summarises the options available to meet the development needs described above.

The development options for the Northeastern Area are comprised of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive because there are solutions which meet several needs for the same investment.

8.6.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions to defer investment discussed in Chapter 8.1.8.

8.6.4.2 Projects for 2020/21

Projects currently underway or planned to start over the next 12 months are listed in Table 8-54.

Project	Description
Seaview Incomer Cable Replacement	Replacing 11 kV cables between the power transformers and the 11 kV switchboard to lift substation capacity.
Silverstream Line Circuit Breaker	Upgrade protection on line feeding Silverstream generation plan.
1 Takanini Grove	Distribution transformer capacity upgrade.

Table 8-54 Northeastern Area Projects for 2020/21

8.6.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 8-55. This information is an extraction from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example, many subtransmission constraints can be solved through HV distribution level configuration change and/or managed operationally.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Issue ID	Category	Constraint	Preferred Option	Investment Period	Investment Amount (M)
C1I1	SUBT	KOR 33 kV subtransmission capacity	Transfer some of PET (KOR) load away to MLG - use the PET 33 kV cable at 11 kV: upgrade MLG ripple plants to a single larger unit, spare the MLG load control 2 HV bays to connect the PET cable to PET CB6. Split the PET 11 kV bus with one half supplied from KOR and the other from MLG.	2021	$1.2
C1I2	SUBT	KOR 33 kV transformer capacity	Same as C1I1	2021	$0
C1I3	SUBT	WNU 33 kV Cable Winter rating	Upgrade WNU subtransmission cable, approximately 150m, complete this task as part of the TP GFD IDID upgrade	2022	$0.4
C1I4	DIST	WAT 5 feeder Capacity	Split WAT5 into 2 separate feeders, extend WAT11 to pick up some load on WAT 13 and use WAT 13 to supply some of the WAT5 load	2025	$0.5
C1I5	SUBT	WNU 33 kV TB Transformer (ex PET) winter rating	Operational Control. Demand side response to reduce TB capacity and reliability issue	2022	$0.2
C1I6	DIST	MLG Feeder 4	Load Balance to KOR after KOR upgrade, demand response	2023	$0.2
C1I7	DIST	WAT 9 feeder Capacity	Transfer Griffins load to GRA by swap feeders CB and SW	2026	$0.1

Issue ID	Category	Constraint	Preferred Option	Investment Period	Investment Amount (M)
C1I8	SUBT	SEA subtransmission cable capacity	Rebalance load between SEA and GRA	2022	$0
C2I1	DIST	BRO 8 feeder capacity	Transfer load to adjacent feeders - BRO 5 and 10	2021	$0
C2I2	DIST	HAY 2722 (Silverstream) feeder capacity	Transfer some load to TRE 05 feeder and TRE 10 feeder	2021	$0
C2I3	DIST	MAI 6 feeder Capacity	Establish a tie between BRO 11 and MAI6 at S2824 Pine Ave A, this will also provide a tie between BRO2, 6 and 11.	2023	$0.5

Table 8-55 Northeastern Area Development Summary

8.7 Secondary Assets NDRP

This section provides a summary of development needs and project plans from NDRP for the secondary asset projects under the system growth and reinforcement category.

The Secondary Asset Strategy is developed based on the overall Asset Management Strategy, which is implemented based on the Asset Management Policy.

From the Secondary Asset Strategy there are separate standards and guidelines developed for each key asset category. The Secondary Asset NDRP is development by following the process of assessing the current fleet, long term needs and development opportunities against the network standard.

The location of the Protection Standard in the document hierarchy is shown in Figure 8-71.

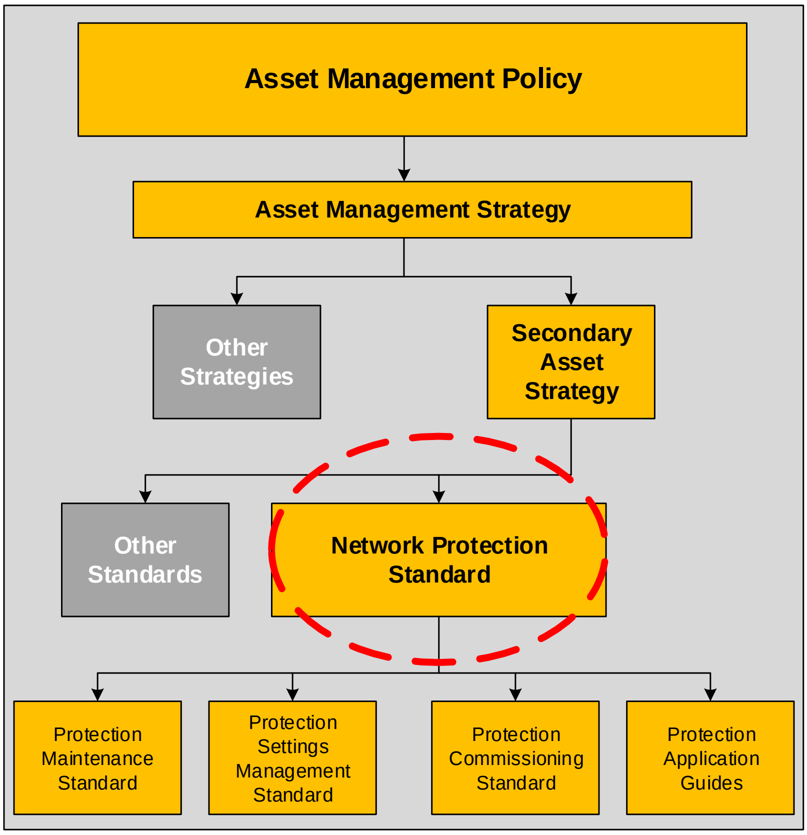


Figure 8-71 Document Hierarchy for Secondary Systems

8.7.1 SCADA/Protection Radio

The need for flexible and robust communications is growing rapidly within all sectors. Proliferation of Industrial Internet of Things (IIoT) and advancements in technology are driving the necessity for having widespread access to communication.

The secondary asset area of an EDB is heavily affected by communication as it is the common mechanism to provide service for protection, SCADA and demand management.

Although WELL has installed some optical fibre circuits, a heavy reliance on an aging electrical media based pilot cable communications system remains. Network reinforcement is required not only to replenish the existing functionality but also align with the requirements of modern equipment used for the critical network services.

The capital investment required to install underground fibre or hanging aerial fibre on overhead circuits is significant and therefore becomes cost prohibitive when compared to a wireless solution. The installation of fibre does however become viable when considered in opportunistic scenarios where trenching is already being undertaken such as primary cable installation.

WELL is therefore investigating the feasibility of investing in a multi-tier wireless network to carry the communication of operational services.

Due to the differing nature of the operational services and their criticality, the service and performance levels required also differ and as such a multi-tier approach has been taken to defining the requirements of a new wireless network integrated with existing underground network components. Table 8-56 details each proposed tier.

Tier	Application	Technology and minimum requirements
1	Inter-data centre or master stations, backhaul, control room.	Fibre, microwave, >100Mbps, <20ms latency, full duplex
2	GXP to Zone substations, between Zone substations and zone substations, or key switching stations with protection, SCADA, etc.	Fibre, microwave, Pilot cable, >10Mbps, <10ms latency, low jitter, high symmetry, full duplex
3	Zone substations to distribution stations, SCADA	Fibre, UHF, 4G, Pilot cable, >60kbps, Half duplex
4	Distribution stations to end user devices	UHF, 4/5G, Low power narrowband radio, spec depends on the actual requirements

Table 8-56 Communication Requirements

Detailed radio frequency planning is currently being undertaken to determine the suitability of various microwave links and their feasibility alongside the required performance criteria and local geographical conditions. This study also considers Radio Spectrum Management (RSM) requirements, availability of unused channels and the overall strategy of integrating the multiple tiers in a cost efficient and resilient configuration.

8.7.1.1 Tier 1 Network

A large bandwidth, high criticality network used to backhaul SCADA and load management services to either of the master stations operating in a ring topology to compliment the main and backup master stations located at the Central Park and Haywards nodes.

An early concept Tier 1 wireless network is shown in Figure 8-72 below. This will provide additional capacity and resiliency to the currently operated WELL communication network.

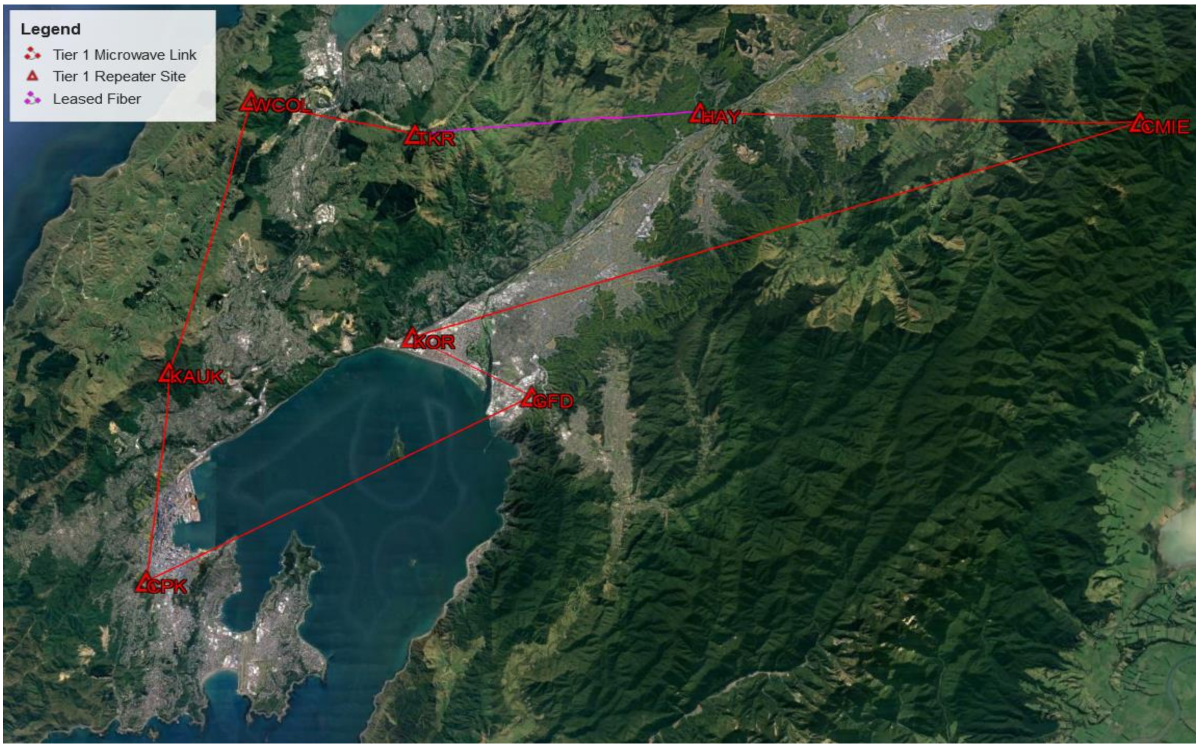


Figure 8-72 Tier 1 Wireless Network Concept

8.7.1.2 Tier 2 Network

The Tier 2 network would be responsible for transporting the protection signalling between zone substations and GXPs along with SCADA and load management data from the zone substation as well as additional distribution substations that have been data concentrated at the zone substation.

This network's performance is similar to the proposed Tier 1 network however it will not require as much bandwidth, as each link will not be backhauling as many services. Tier 2 does require lower latency and higher symmetry than Tier 1 to carry the protection signalling.

An early concept Tier 2 wireless network is shown in Figure 8-73.

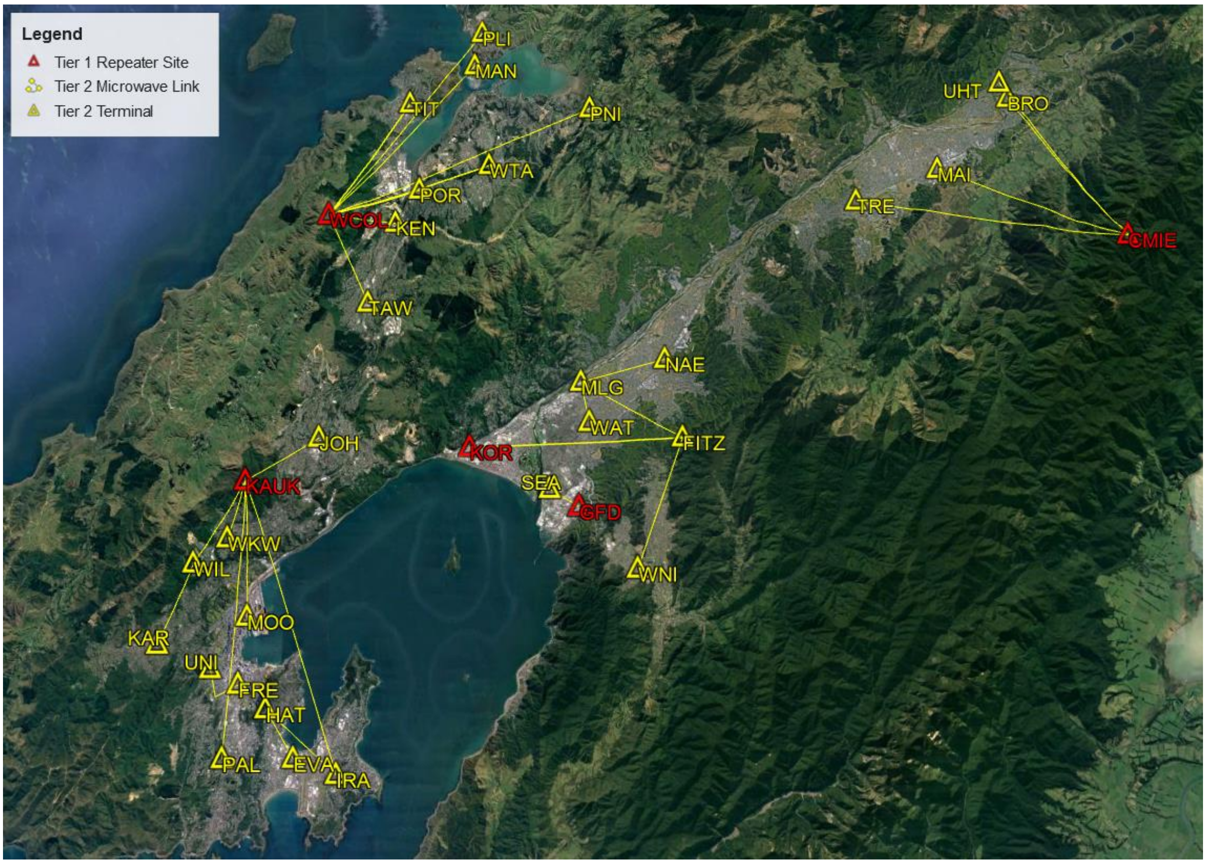


Figure 8-73 Tier 2 Wireless Network Concept

8.7.1.3 Tier 3 Network

The Tier 3 network is proposed to replace the existing analogue SCADA radio network by continuing to use the mobile radio UHF spectrum however with digital modulation.

This will require four high site repeaters (already utilised for Tier 1 and 2) to broadcast across the WELL network and achieve a high level of coverage. Other equipment changes will be required at the remote sites, such as replacing the antennas and base stations. The data will be concentrated at each high site, and backhauled to the master station using the Tier 1 network.

8.7.1.4 Tier 4 Network

Lower criticality assets will utilise a wide area network (WAN) consisting of public 5G/4G and/or a public/private narrowband low power radio system. This network can be used for Tier 3 sites that do not obtain sufficient coverage but will be optimised for equipment with low bandwidth, low priority and a small physical footprint that does not justify the expenditure of equipment required to host on the other Tier networks.

Such equipment is expected to include line fault indicators, LV monitoring, and thermal monitors.

8.7.2 Transpower Protection Replacement

Transpower are replacing protection equipment at several of the GXPs that supply WELL. This equipment integrates with WELL protection and SCADA equipment therefore when replacements occur, changes are also required on WELL's network equipment.

Generally, modification to WELL equipment is limited to protection coordination studies, setting changes, SCADA configuration changes and minor wiring modifications.

8.7.3 Summary of Network Development Plan

A summary of the development plan is listed in Table 8-57. This information is an extract from the NDRP, which provides detailed development options and feasibility analysis.

Issue ID	Category	Constraint	Preferred Option	Investment Period	Investment Amount (M)
P2I2	SAP	Future communications requirements and limitations on existing systems	Supplement existing assets with new radio links	2021-24	$5.1
P2I5	SAP	Protection system limitations and security	Protection system redesign	2026	$2.6

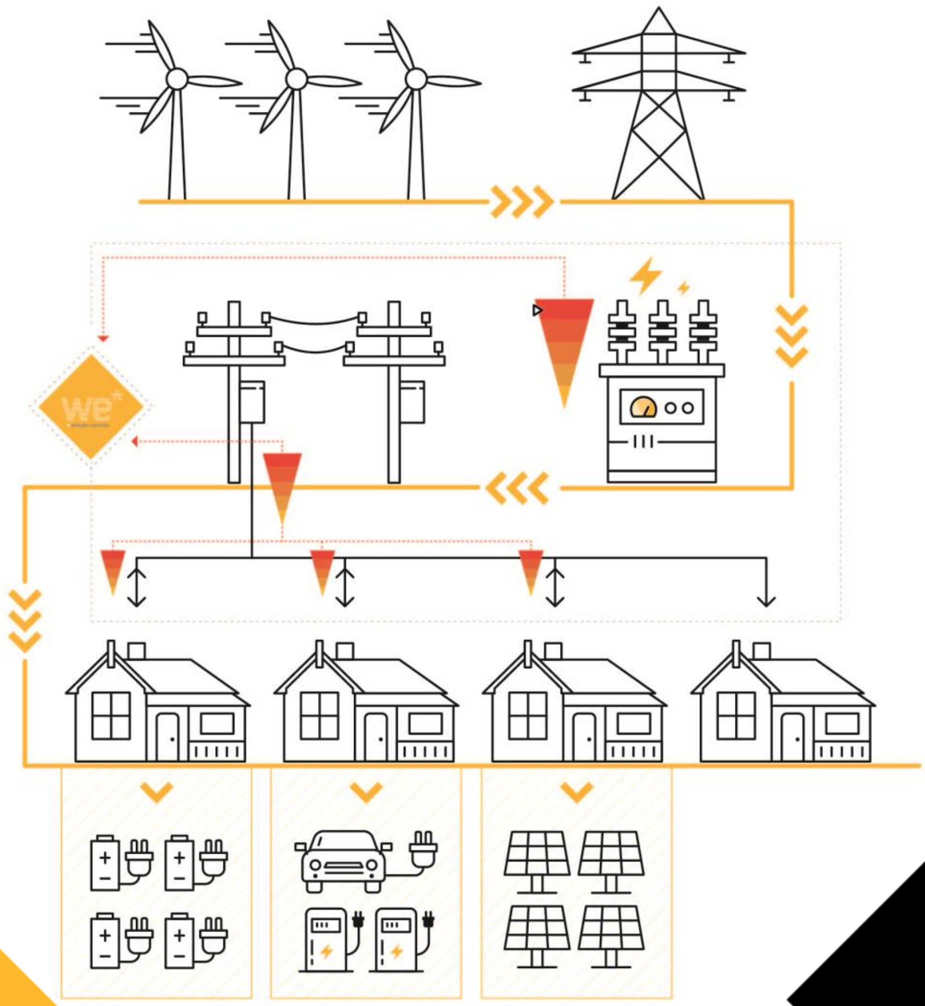
Table 8-57 Secondary Assets Development Summary

8.8 System Growth and Reinforcement Summary for 2020-2030

From the details in the sections above, WELL's network development and growth capital expenditure forecast is summarised in Table 8-58.

Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Primary - Southern	1,960	4,800	4,020	2,200	2,600	2,500	2,900	600	6,000	7,000
Primary - Western	150	20	4,300	4,400	3,750	8,560	7,800	8,000	4,000	5,000
Primary - Eastern	170	1220	600	700	500	500	500	500	500	500
Distribution Sub	500	10	10	10	10	500	500	500	500	500
Secondary Assets	300	2,175	1,265	1050	300	300	600	600	600	800
System Growth Total	**3,080**	**8,225**	**10,195**	**8,360**	**7,160**	**12,360**	**12,300**	**10,200**	**11,600**	**13,800**

Table 8-58 Capital Expenditure Forecasts
($K in constant prices)



Section 9

Emerging Technology

9 Emerging Technology

The key for New Zealand moving ahead on a more cost efficient, resilient and cleaner electricity network, depends on how the DERs are integrated with the distribution network, specifically the local LV and HV distribution assets. DERs will significantly increase the energy choices for end use consumers.

Adoption of DER will change the way the electricity distribution network is operated, from single direction power flow to a multi-flow system. Customers will have a choice for greater interaction with the electricity sector by offering and coordinating their energy resources through storing, generating, consuming or discharging energy back into the network. As a result, one of the key focuses in WELL's DER development roadmap is how the company can support the uptake and integration of customer devices, while maintaining a safe, secure, and reliable distribution network for customers both with and without DER.

9.1 Background

The impact of emerging technologies on the electricity network includes:

- Increased demand due to electrification of transportation and industrial processes;
- The creation of two-way power flows as customers install local generation which discharges energy back into the network. Local generation and batteries can also change customer demand profiles;
- The introduction of household batteries which provides opportunities to manage demand at both household and network levels;
- Reduced demand due to energy efficiency with the adoption of new energy efficient processes and replacement of older equipment;
- Supply quality issues such as voltage fluctuations, low power factors and high harmonic distortion levels predominately on LV circuits and customer connection points;
- New consumer behaviour following adoption of new technologies with digital interfaces that allow higher level of device/appliance interaction;
- Improving economics of new technologies which make it easier for customers to develop distributed energy resources;
- New technologies adopted by consumers which provide cost effective and reliable energy solutions. These technologies allow optimising of asset utilisation and possible use of demand side management by electricity networks; and
- Changes in regulation bringing new requirements and policies on emerging technologies may lead industry participants to adopt new asset management practices.[51]

WELL's new technology development plan is consistent with views of the Business New Zealand Energy Council who have highlighted three major themes for change in the energy industry:

[51] Industry regulators have indicated desire to enable adoption of emerging technologies, which may lead to changes in the regulatory requirements.

- Digitalisation;
- Decarbonisation; and
- Decentralisation.

The changes due to new technology and their impact need to be addressed at the distribution network level. This requires collaborative engagement between regulators, distribution companies, consumers, equipment suppliers, retailers and Transpower.

Changes in customer requirements have the potential to significantly alter the expected network loading and therefore the forward investment required on the network. The increase in demand and impact on supply quality could affect existing customers connected to the LV network. Improving visibility of usage and demand in the LV network will enable WELL to better manage the LV assets that most consumers are connected to.

An increase in EV uptake, in line with government targets,[52] may start to significantly impact parts of the LV network in the next 5-10 years, resulting in power quality and asset performance issues if not managed effectively. For example, a standard NZ domestic Type 2 EV charger is capable of delivering 32A, which is equivalent to two domestic hot water cylinders added to the household load. Accommodating this extra load will require effective load management so EDBs can reduce, delay, or avoid large network reinforcement requirements. WELL introduced Time of Use pricing for EV owners in 2018 to incentivise EV users to charge their vehicles during less congested periods. Time of Use prices are being extended to all residential customers in 2020 to assist with load management.

Figure 9-1 shows the future model where consumers start to invest in emerging technologies such as PV, battery storage systems and EVs. This leads to a potential two-way power flow between network operators and consumers. Uncontrolled energy use on the network will lead to expensive network reinforcement. In order to avoid such reinforcement requirements, the network operator will require greater visibility of the network and a better understanding of consumer demands.

[52] Government target of 64,000 electric vehicles in New Zealand by 2021

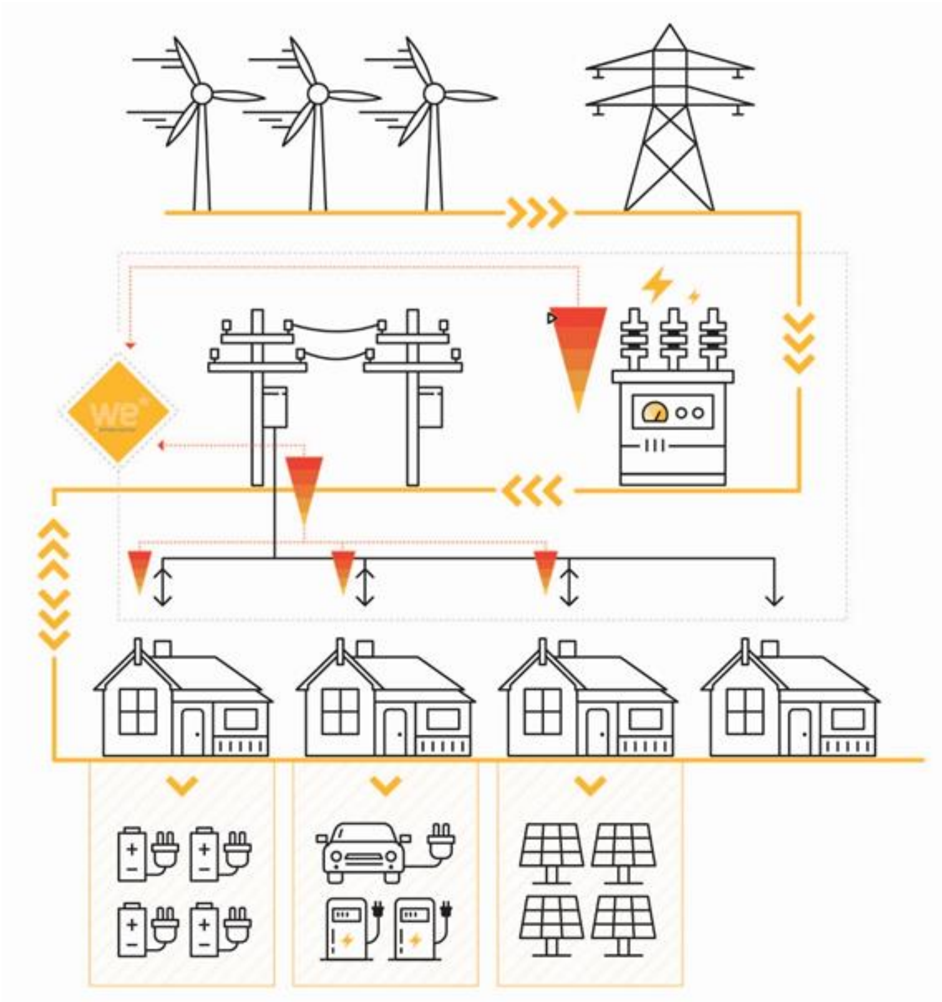


Figure 9-1 Potential Future of the Electrical Network

Depending on the mix of new technology that occurs across the network, there is also an increased risk of stranded network assets. WELL's view is that this will generally not be the case in the Wellington region. WELL expects there to only be small sections of the network where underutilisation may be a risk to capital recoveries over the lifetime of the assets, rather than for the majority of the network.

9.2 WELL's Innovation Focus

The primary focus of WELL's new technology advances is to:

- Enable the adoption of transformational innovation and be adaptive and responsive to uncertainty in a fast moving environment;
- Adopt new technologies that improve safety, reliability of supply, and asset efficiency, avoid unnecessary expenditure, and improve WELL's ability to satisfy legislative requirements;
- Minimise and manage network risks from the adverse impacts of emerging technologies;
- Develop cost effective, environmentally friendly, innovative solutions that defer or reduce network investment expenditure as opposed to traditional network solutions; and

- Enable a seamlessly integrated data exchange platform for the industry and consumers to take advantage of opportunities offered by adopting these new technologies.

9.3 Developing a Business Case for New Technology

WELL's initial analysis shows that managing congestion using distributed energy resources will allow WELL to avoid increasing the capacity of the existing network to meet the expected exponential increase in energy demand from the uptake of EVs. Figure 9-2 compares the capital required to meet expected increase in demand from emerging technology (e.g. demand increase due to EV pentation), with and without deploying the capability to monitor and manage distributed energy resources. While the initial analysis does not provide exact levels of expenditure, it does show the proportional difference in expenditure.

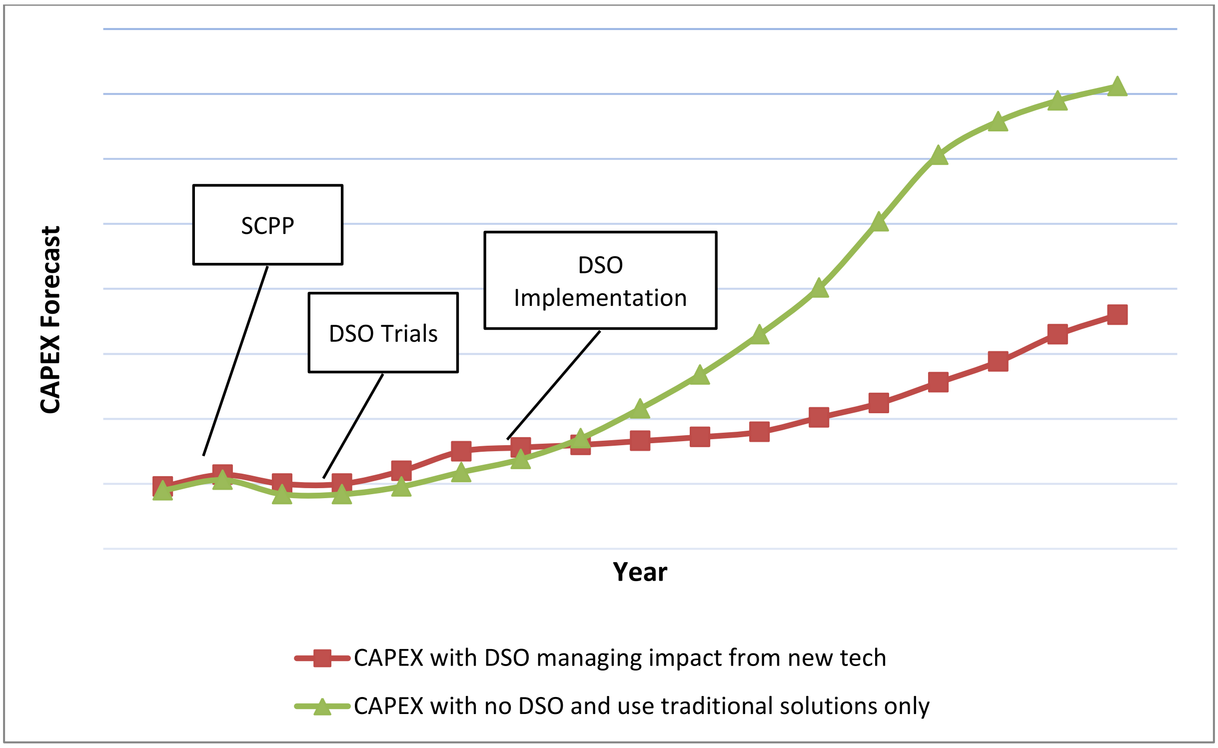


Figure 9-2 CAPEX Forecast for Different Development Options

WELL's initial analysis indicates that the savings to customers from managing congestion using DER could be significant. However the introduction of new technology is risky and the investment is still expected to be significant.

To develop a robust business case and give customers confidence that the investment in new technology will provide lower prices in the future, the new technology must be first trialled. This AMP includes a range of trials which will test the viability and effectiveness of using distributed energy resources to manage congestion.

9.4 Funding Assumptions

WELL is currently funded through a Customised Price Path (CPP) which expires in 2021. WELL will then move onto the DPP3 funding model. Both of these funding models use the AMP as the basis for capital funding allocations for asset renewals and system growth.

The funding for the trials has been included in this AMP, with an initial cost of around $0.6 million per annum over the first five years and rising to around $3 million at the end of the planning period. This funding will not be sufficient to fully implement the transformation required. A detailed description of the trials, and what part of the proposed solution the trial is testing are provided in Section 9.7, and cost forecasts are summarised in Section 9.8.

After the trials have been completed, funding for the capability to monitor and manage distributed energy resources will need to be supported with a business case demonstrating that the benefits will be greater than the cost to customers. WELL does not have the data to develop a detailed business case yet, and for this reason, this AMP does not include funding for:

- Implementing a full LV monitoring system such as a dual smart metering solution which has been implemented on some other networks in New Zealand and Australia. WELL believes this should be delivered by a cheaper solution such as the roll out of an enhanced customer-owned smart meter where one meter at the customer's house meets both the industry's and the customer's needs;
- The full capital and operational costs of a potential DSO operating exchange system. WELL sees this as being an industry wide collaborative solution with multiple stakeholders and partners;
- Long term network reinforcement cost via traditional solutions to accommodate significant demand changes due to uncertainties in the uptake of the emerging technology; or
- The impact that an exponential uptake in EVs might have on demand.

Network capital expenditure under the DPP methodology is limited to 120% of the last 10 years average expenditure. Furthermore, DPP operating expenditure is based on historic expenditure and cannot be easily adjusted for new costs. If EDBs require higher levels of funding outside of the DPP constraints then under the current rules they need to apply for a CPP. A CPP is intended to be used in exceptional cases where EDBs need expenditure outside of what fits within the DPP constraints. A CPP application is resource intensive and expensive. The Commission can also only consider four CPP applications per year.

The increase in energy demand from EVs will be nation-wide and is likely to impact most EDBs. The higher levels of funding are likely to become the norm, rather than the exceptional circumstance a CPP regime was designed for. It is therefore likely that the Part 4 funding model will need to be adjusted to reflect that distribution networks will need to increase capacity to meet increasing electricity consumption as vehicles change from petrol and diesel fuel to electricity. Changes are also likely to be needed to how operating cost allowances are calculated to reflect that EDBs may want to purchase DER services to help manage congestion.

In November 2019, the Commission published the final decision on DPP3 reset. This included the introduction of an innovation project allowance for up to 50% of the total cost of approved innovative projects in the assessment period, but not exceeding 0.1% of the total allowance in the regulatory period. While this innovative fund is in line with Part 4 of the Commerce Act to promote the long term benefit of consumers, the actual allowance amount is insufficient for EBDs to deliver the innovation projects that are likely to be needed.

9.5 Collaboration

WELL is continuing to work with its sister companies around the globe, as well as New Zealand industry bodies, on a network transformation roadmap. The key elements that have been prioritised by the industry are a DER open network standard, access to metering data, and LV equipment monitoring. Additional investment will be required to introduce monitoring technology to provide visibility of customer DER. The coordination of retailers and load aggregators to optimise DER for network operators is expected to defer network capacity investment resulting in a long term benefit for customers.

9.6 New Features and Regulation

New technology could provide innovative network solutions for voltage support, supply quality, and network capacity management. EDBs will need to test and develop how the technology could be used and whether it could provide a better alternative to traditional solutions. In December 2019, the Authority proposed the change of Electricity Industry Participation Code (EIPC) Part 6 on DG/DER inverter technology requirements for a specific application process that has the potential to dynamically manage system constraints and enable wider DER adoption. WELL supports the adoption of additional functional requirements on advanced inverters and will continue working with the industry on promoting other improvements, including demand response function on DERs.

Under the Commerce Act, Part 4, Clause 54Q – Energy Efficiency, the Commission must promote incentives and avoid imposing disincentives for EDBs to invest in energy efficiency and demand side management to reduce energy losses. New technology offers opportunities to reduce network losses. An energy management platform at the LV level could assist in co-ordinating two-way power flows with DER. The wider electricity industry will need to co-operate and collaborate to ensure new technology is implemented effectively and efficiently. The benefits from using DER cannot be delivered by distributors in isolation.

Initial industry changes to enable the introduction of disruptive technology include:

a) New technology standards: Introduce new standards for new technology, allowing integration at lower cost;

b) Mandatory notification: Require customers who want to install new technology to apply to their lines company (similar to the existing distributed generation rules for solar). This will ensure that the installation of the new technology complies with the standards of the network for two way power flows;

c) Congestion standards: Introduce standards on how congestion is defined and require network congestion to be disclosed;

d) Low voltage monitoring: Improve the monitoring of the network particularly LV with DERs where current monitoring is inadequate and where changes are most likely to impact supply quality;

e) Management of DER: Investigate and trial platforms that enables the management of distributed energy resources;

f) Support with efficient prices: Introduce efficient prices that reflect the benefits and encourage the use of DER;

g) Data streams from smart devices located behind the meter: Require LV data to be made available to the supply chain. This would improve EDBs visibility of the LV network, allowing them to manage demand effectively and to calculate efficient prices for services using disruptive technology; and

h) Available funding: Ensure that funding is available to develop and implement the new technology.

Such changes require regulatory support to ensure these relatively simple controls can be implemented. As well as working with industry and regulators to ensure these changes are implemented in the short term, WELL continues to learn from others and trial new technologies to prepare for the changes ahead. WELL believes this is a prudent and flexible approach to manage the uncertainty associated with new and emerging technology, and will avoid overbuild in the short term.

It is WELL's view that new systems which enable LV monitoring and analytic capability, and working closely with other industry participants will deliver the best long-term solution for New Zealand.

9.7 Initiatives

WELL's consideration of new technology is still at the early stages of strategy development and concept validation. Most of the activities planned over the next two-three years are research and development type projects. These will help form WELL's long term strategy and financial plan for the remainder of the planning horizon. The uncertain nature of emerging technology development and funding limitation is driving a conservative approach of testing the technology to avoid large in investments in inappropriate solutions (a least regret approach to the technology road map development).

WELL's emerging technology programme will focus on eight key areas. These are summarised in Figure 9-3.

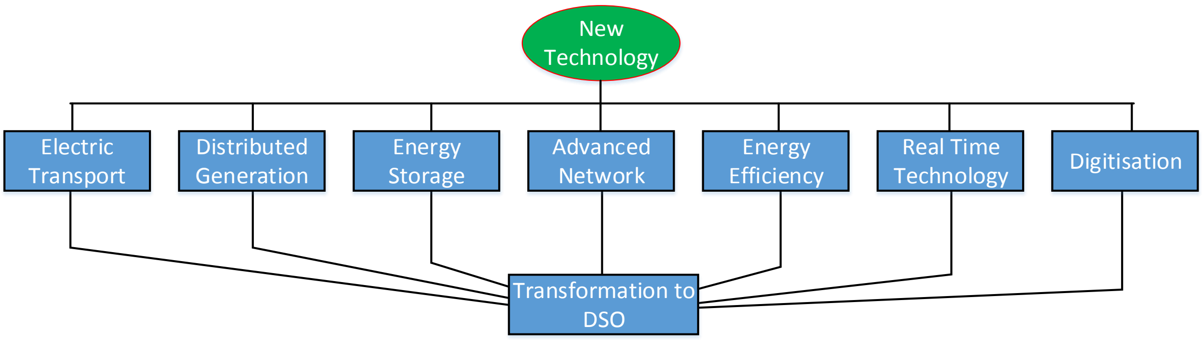


Figure 9-3 Major Development Areas under WELL's New Technology Strategy

9.7.1 Transformation to a Distribution System Operator (DSO)

What it is and why it matters

A DSO platform provides the tools and processes to coordinate DERs across a network so that their demand requirements can be managed within reliability and quality limits and within network constraints. A DSO platform manages DERs in a cost effective manner that provides mutual benefits to all stakeholders. WELL's DSO development plan will focus on laying the foundations to prepare for a transition to a DSO through innovative projects. WELL expects the transition to a DSO will not be trivial and will take a long time. It requires investment, including the initiatives outlined in this development plan that enable new customer choices, promote competition, and offer cost-effective solutions.

EDBs are responsible for maintaining power quality as required by the Electricity (Safety) Regulations 2010. While EDBs may not be the only candidate to be the DSO provider, they are best placed to understand and manage local technical electricity supply issues and set technical standards governing emerging technology to network connections.

What the future holds

Through collaborations with key stakeholders, WELL will take a multi-step approach to develop into a DSO. Figure 9-4 shows the stages of transformation from a traditional distribution network operator (DNO) to a DSO.

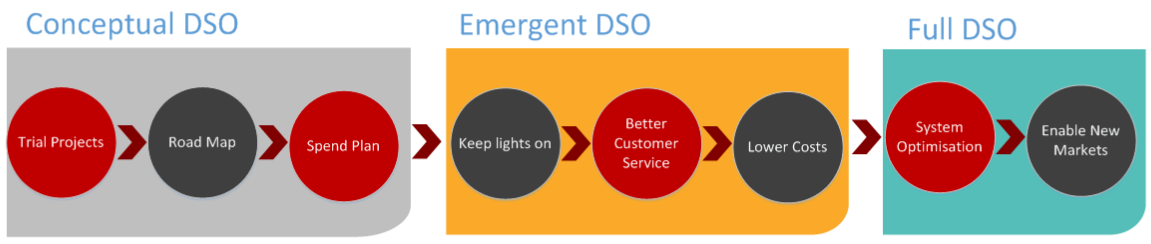


Figure 9-4 DNO-DSO Transformation Stages

Key development areas are:

- Develop a DSO transformation roadmap. WELL is working with the ENA to develop the New Zealand network transformation roadmap which will consider different operating models;
- Understand the new service model of co-ordination platforms and market arrangements through DSO trials. Figure 9-5 and Figure 9-6 show possible market arrangement options for DSO service operating and commercial models;

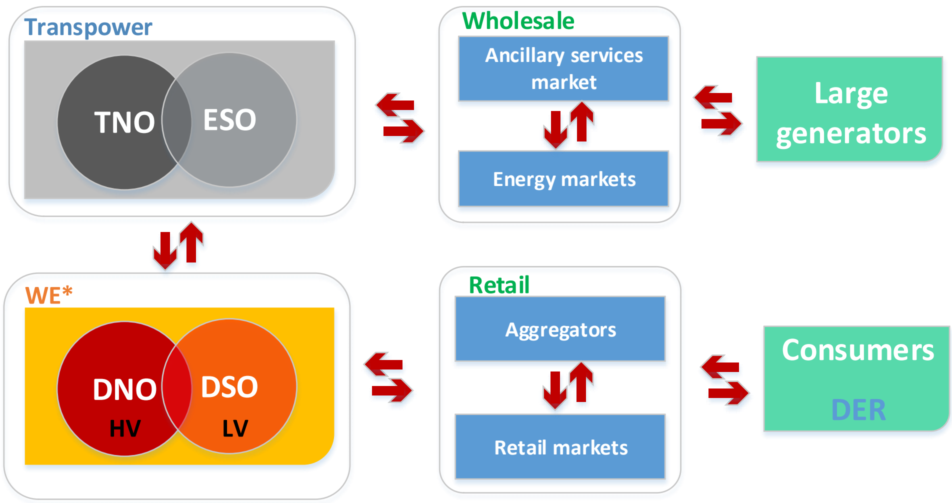


Figure 9-5 Strawman Proposal for the DSO Model

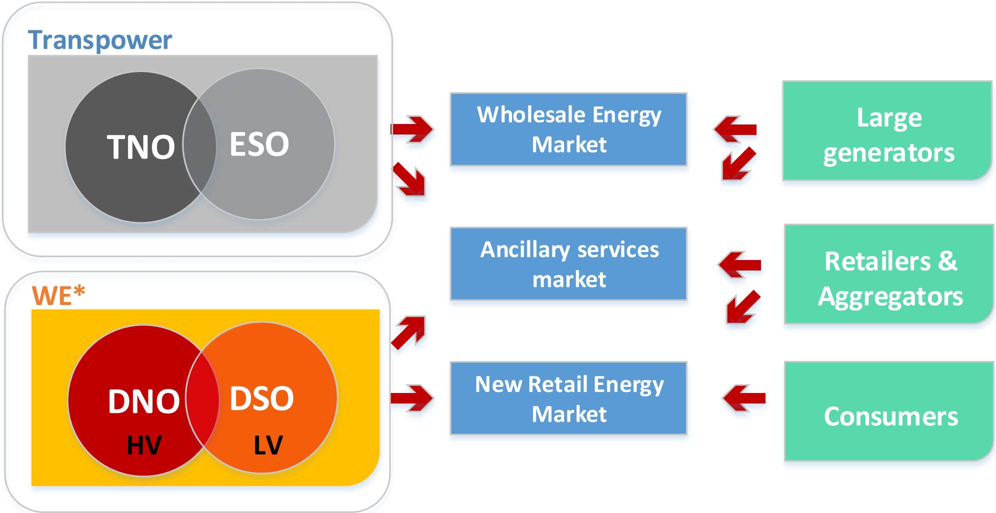


Figure 9-6 Alternative Option for the DSO Model

- Work together with retailers to investigate DERs and trial load balancing at selected locations:
    - LV feeder balancing
    - HV/LV feeder load balancing between substations: dynamic support between adjacent substations to meet load conditions, which supports the deferral of primary network reinforcement
    - Zone substation feeder group load balancing
    - Information exchange platform and trading transactions.
- Investigate and trial an Advanced Network Management (ANM) platform for export constraint management starting with a limited number of microgrids (see Section 9.7.5);
- Use new technologies as alternatives to conventional solutions to achieve much greater efficiency of the network;
- Design tariffs to incentivise customers to participate in DSO services which support the efficient operation of the market. The tariff will aim to avoid cross-subsidisation given that the customer will engage with the network in different dimensions: consumption, generation, storage provision, voltage control, load balancing and demand response
- Understand the DNO and DSO system interface and how to build a new platform which interfaces with external systems. Figure 9-7 shows one possible system integration model for DSO Operation;

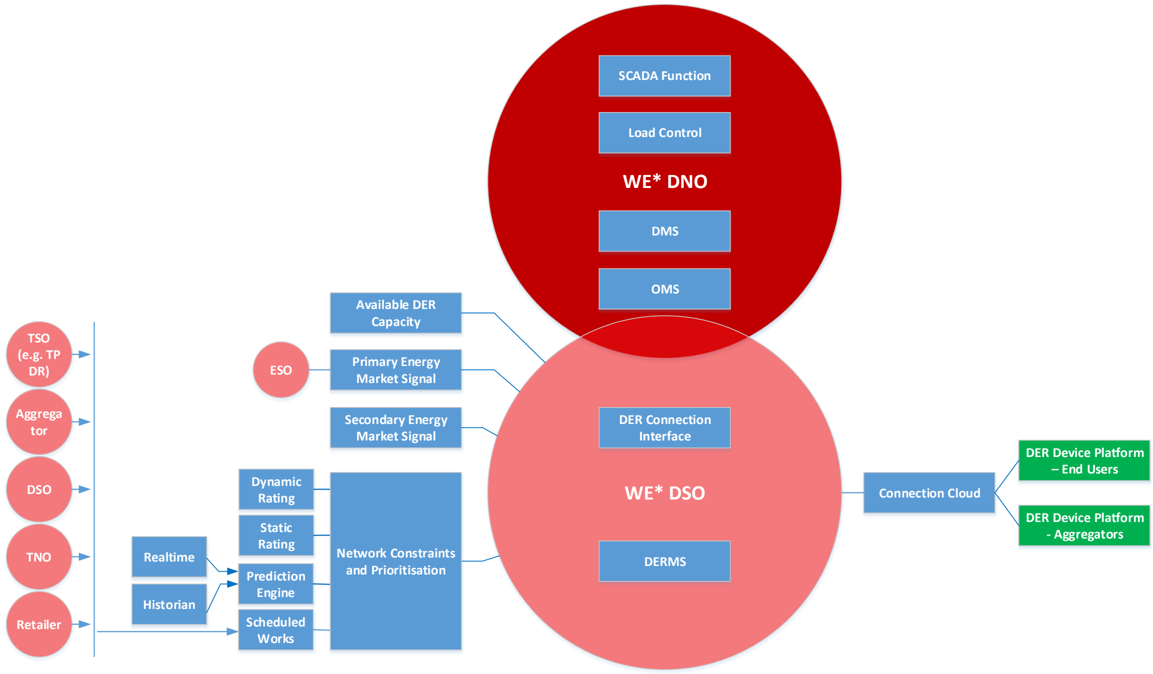


Figure 9-7 Possible DSO System Integration Model

- Consider power quality and load balancing. Distributed energy resources enabled by emerging technologies[53] will add to the complexities of the multi-directional flow of electricity. This will pose power quality challenges. However, connected devices can also be configured and coordinated with a higher degree of flexibility to manage power quality and load balancing. New market models and operating platforms (network control and trading) will be required to manage power quality;

- Integrate corporate information technology (IT)[54] and operational technology (OT)[55]. Historically IT and OT reside in different parts of the organisation. However, it is vital to integrate these to achieve successful implementation of new technologies and faster business process turnaround. This will provide business capacity to manage the complexity introduced by a smart network configuration and high level of flexibility that customers are coming to expect; and

- Change the skills required of WELL's workforce to ensure greater deployment of technologies.

9.7.2 Electric Vehicles (EVs)

What it is and why it matters

Electrification of the transport fleet is a key focus for New Zealand to achieve the Government's decarbonisation targets, and has the potential to grow exponentially in the next decade. EVs and other forms of electrified transportation will increase energy demand across the network when they plug in to charge.

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[53] The interface of most customer devices and the network will be driven by inverter technologies.

[54] Information technology mostly refers to software applications for commercial decision making, planning, business processes management and resource allocation.

[55] The operations side is responsible for execution, monitoring and control of the electric system, making sure the network is operating within the allowed ranges of reliability, quality and cost set by the regulations and parameters of the corresponding agencies. This category includes SCADA, OMS, EMS, GIS, etc.

The relatively low number of EVs present in Wellington means there has been minimal impact on WELL's network to date. With the government setting a goal of reaching approximately 64,000 EVs on New Zealand's roads by the end of 2021, and this number doubling every subsequent year,[56] this situation is set to change. By proportion of population for the Wellington region, this represents up to 6,000 EVs by 2021 and around 100,000 EVs by 2030 (assuming a sustained adoption rate). The actual impact of these EVs connecting to the network at the same time for battery charging, depends on charger types, duration and connection capacity, but could be adding more than 150MW to the peak demand if not managed carefully. This will lead to a significant change in WELL's asset planning requirements and infrastructure investment portfolio.

The ability to monitor and manage EV charging is a fundamental part of WELL's DSO development plan and will be essential for responding to this emerging technology. At the LV connection point, there is potential for uneven network distribution due to irregular distribution of EVs across socio-economic groups and locations. Figure 9-8 and Figure 9-9 show the impact of varying rates of EV penetration compared to existing load and voltage profiles. The demand model illustrated is based on a standard 200kVA distribution transformer with no demand side management in place. Based on this scenario, transformer, switchgear and conductor upgrades will be required to meet the additional load growth and excessive voltage drop with unmanaged EV charging. This will translate into a higher EV ownership cost for consumers.

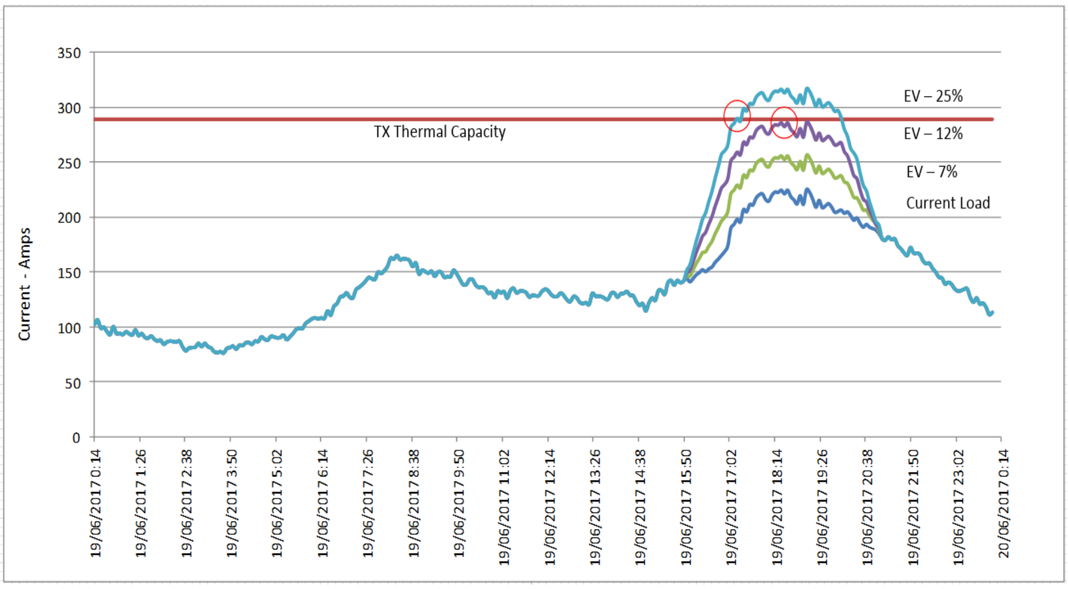


Figure 9-8 Distribution Transformer Load Profile by EV Penetration Rate

56 http://www.transport.govt.nz/ourwork/climatechange/electric-vehicles/

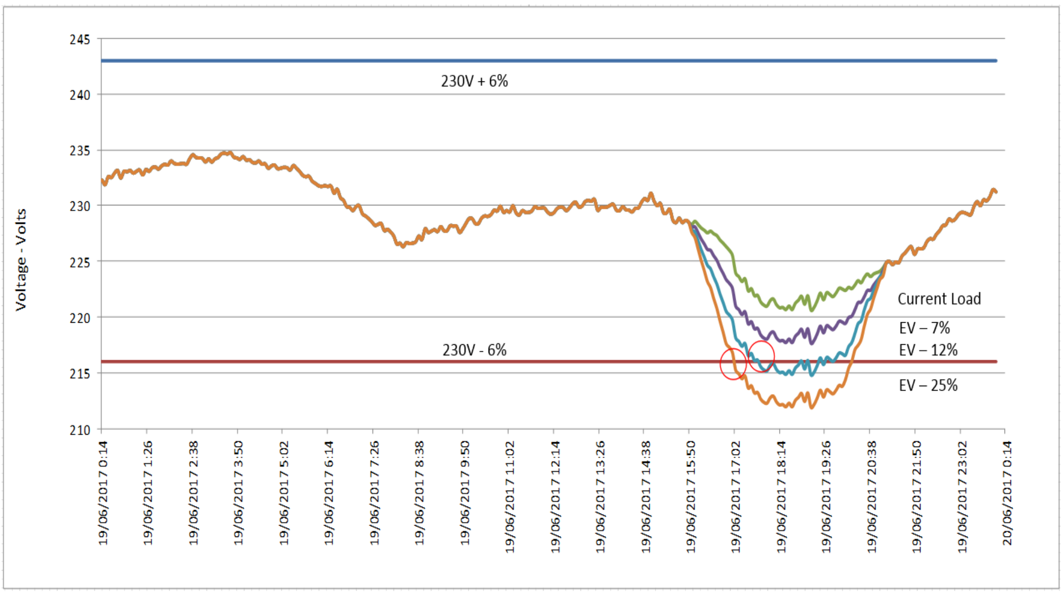


Figure 9-9 End of Line LV Voltage Profile by EV Penetration Rate

What WELL has done so far

Steps are already underway to signal through cost reflective prices, times that the network is less congested and better able to support EV charging.

WELL published an EV study report in July 2018[57] to improve communication between stakeholders and WELL and understanding of the new tariff structure, generate public awareness, and build relationships with suppliers and users. Talking to early EV adopters and understanding their thinking helps WELL to form long term strategy to manage EV charging.

Some of the activities undertaken by WELL in support of EVs include:

- Vehicle charging: testing new EV models to assess their impact to the network;
- Vehicle to grid (V2G) investigations: this technology uses the car battery to support the bi-directional flow of energy to offset the overall load or even back-feed to the grid to support upstream network constraints. The technology is now proven and ready for market, though not yet commercially available.[58] V2G has potential to support the network at peak load times and in managing short-duration outages;
- Upgrading WELL's EV fleet chargers with control capability through a new firmware that supports open charge point protocol (OCPP). This allows WELL to study the control function through a trial project;
- Regional EV strategy development with key stakeholders. WELL has participated in the development of a regional strategy to deliver benefit to the region;
- Developed an EV tariff encouraging EV owners to charge EVs overnight (9 pm to 7 am) at a reduced rate with the aim of moving demand away from peak periods; and

[57] Understanding the home charging behaviour of EV customers: https://www.welectricity.co.nz/disclosures/pricing/evtrial/

[58] Information on V2G technology from a major EV manufacturer

- Run an internal trial with staff using EVs from the corporate fleet after hours to provide information on usage patterns and network demand.

Since early 2019, WELL and its selected technology partners have initiated trial projects to develop a platform that interfaces between a clustered EV charger fleet and network assets. The preliminary trial results were presented to both the Authority and the Commission, and other industry forums.

In 2019, additional support and funding was provided by EECA through the Low Emission Vehicle Contestable Fund on WELL's "EV Connect" project (~$600k total cost). One of the key highlights of this project is not just implementing a solution that works best for WELL, but partnering with other stakeholders in the value chain, including retailers, fleet aggregators and end consumers to realise the mutual benefit. This project contains three steps with the purpose of building a business model and technology platform for "smart" charging solutions interfaced with the network to manage peak demand. The project will run through 2020 with an expected completion date in mid-2021.

<u>What the future holds</u>

Key observations gathered so far include:

- EVs are not typically connected to a separate meter so the cheaper rate (EV tariff) applies to the entire household use. As domestic consumption is generally low during the day, the new EV tariff will have little impact on revenue. The benefit is in encouraging consumers to shift demand to off-peak periods;

- EV charging during off-peak periods is expected to raise network utilisation which will increase further with wider EV adoption. In addition, EVs retain a residual charge in their batteries which could be injected back into the network and further supress the evening peak. This has the added benefit of potentially deferring investment to expand network capacity; and

- While there has been an increased uptake of commercial charging stations over the past three years, the density and distribution of these charging stations on the network of has not yet raised peak demand.

9.7.2.1 Public Bus Services

The Wellington trolley bus system has recently been decommissioned. It is being replaced by a new electric bus fleet which will have on-board batteries designed to be charged at designated locations. The Wellington Reef Street Bus Charger project involved working with one of the bus service providers in Wellington and to study the impact of adopting EV transportation on the network. WELL has also been working with the bus service operators and Greater Wellington Regional Council on more dedicated chargers at several other locations. WELL's network will need some reinforcement to accommodate the proposed charging points that are a combination of:

- Fast opportunity chargers to charge the buses en-route. These fast opportunity chargers introduce short duration heavy loads (between 250 kVA to 500 kVA each) which may coincide with peak network load times. This would mean limited load diversity and the need for additional load capacity installed on the network. The benefit of fast opportunity chargers is that their locations will be distributed across the network rather than at a central/single location;

- Slow trickle chargers to charge the buses overnight in the depot. Unlike fast opportunity chargers the slow trickle chargers normally have a smaller output capacity. Overnight charging has the benefit of utilising spare capacity in the network during off peak periods; and
- Other relevant issues that include power quality, energy balance, reverse power flow and signalling.

9.7.2.2 Ferry Services

WELL is also working with ferry service providers in the region on electrification of their new passenger ferry fleet. This will further reduce the overall carbon footprint from public transportation in the region. In 2019, several high level options have been presented to the customer and the final option and design requirements are likely to be concluded in 2020.

9.7.3 Distributed Generation (DG)

What it is and why it matters

DG refers to electrical generation and storage performed by a variety of small, grid-connected devices. Examples of DG connected to the WELL network include:

- Photovoltaic (PV) solar generation. The level of PV penetration in WELL network is still relatively low but there has been an increase in both number of new applications and connection capacity in 2019. While PV installations are the most common form of small-scale distributed generation they currently have minimal impact on the network and demand profile. However, learnings from other countries with much higher adoption rates have indicated the importance of managing PV maximum export level, power quality mode settings and disturbance ride through capability;
- Wind. There are eight wind generation sites connected to the WELL network with a total capacity of 60,715 MVA. The greatest contribution to the installed capacity comes from Meridian Energy's Mill Creek wind farm, which is connected via dedicated 33 kV feeders to the Wilton GXP 33 kV bus. This allows for the direct exporting of power to the national grid and therefore has no significant impact on the WELL network (assuming the 220/33 kV transformers at Wilton GXP remain available);
- Hydro. There are three small-scale hydro plants connected to the WELL network with a total installed capacity of 1,348 kVA. These plants have minimal network impact;
- Waste-to-energy: There are two landfill sites which utilise gas from waste for power generation. With a total installed capacity of 4.2 MVA, they are designed to export surplus energy to the network; and
- Diesel: There are nine diesel generations sites with an installed capacity of 16.3 MVA in the Wellington region, the largest being a 10 MVA installation at Wellington Hospital. Diesel generation serves as backup at these sites or for peak lopping and is not designed for back feed operation.

The improving economics and choices of emerging technologies such as DGs, provide opportunities for customers to reduce electricity consumption from the network and to participate in the energy market. At the same time, risks from over-generation could cause a steep ramping up in energy demand and add more complexity for WELL in balancing load and demand on the network.

The following charts have been developed for illustration purpose only. Figure 9-10 shows projected PV capacities. Figure 9-11 shows the impact of different levels of PV adoption at a zone substation, combined with the load growth forecast over the same period, showing that the PV peak output is not coincident with network peak demand periods.

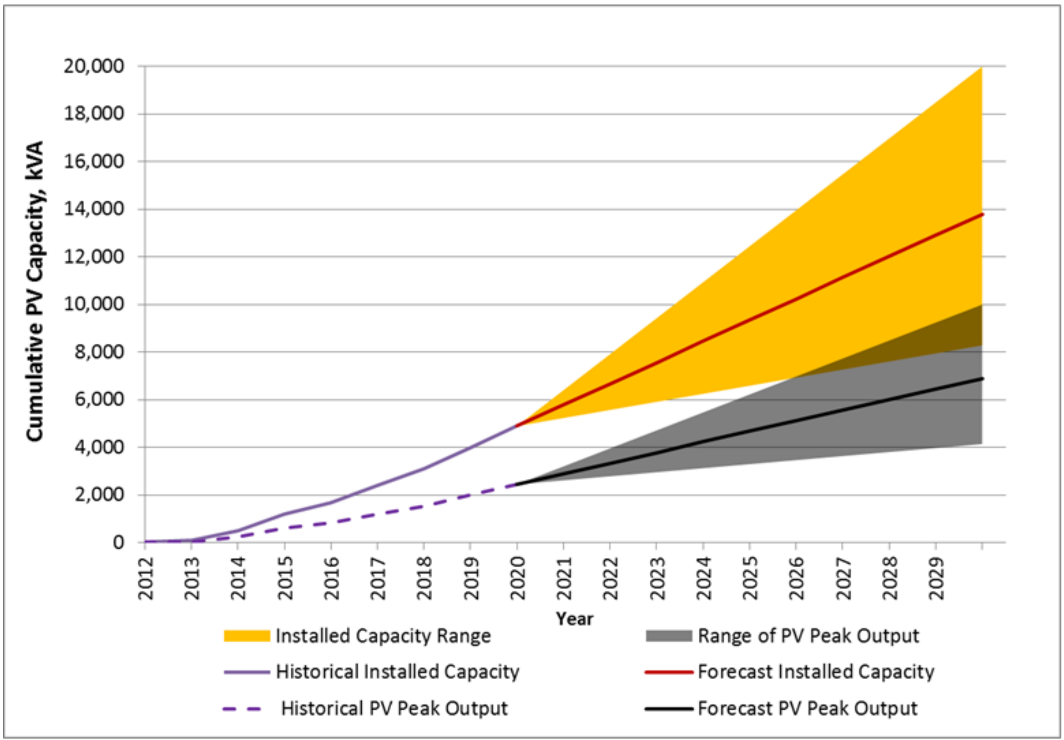


Figure 9-10 Projected PV Installed Capacity and Projected Peak PV Output

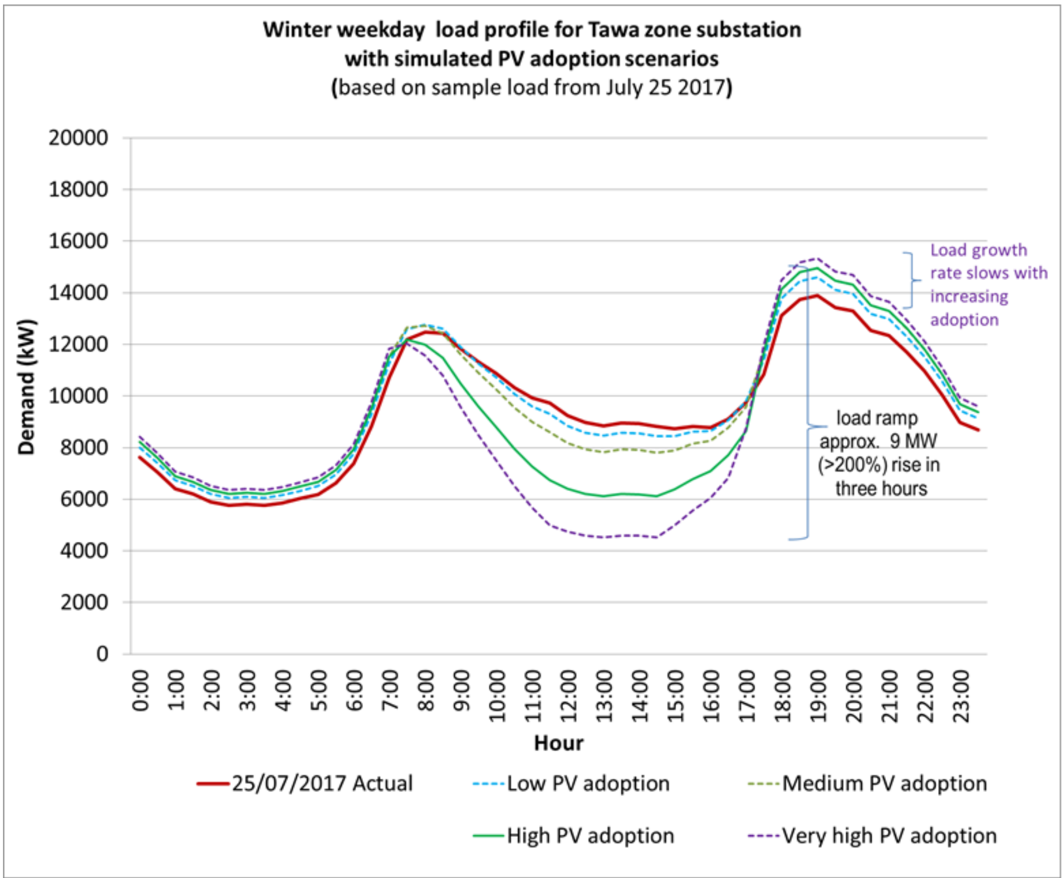


Figure 9-11 Impact of Different Levels of PV Adoption

What the future holds

Issues for WELL with regard to DG connections to the network include:

- New DG installations may not follow the required network connection standard and WELL has limited visibility on DG locations, capacities, penetration levels, functionalities and real-time operation parameters;
- Modern DGs utilise electronic inverters and can pose power quality issues (such as harmonics and voltage fluctuations). While this is not envisaged to be causing issues at the moment, it could with higher penetration and area diversity;
- Incorrect inverter protection settings can cause inability to ride through faults during voltage or frequency excursion events, fault current contribution, islanding protection; and
- Other potential impacts from a higher DG installed capacity in the network are over voltages and network congestion, with upstream equipment overloading due to excessive reverse power flow during high output – low demand period.

To maximise the amount of DG on the network, greater visibility of DG host capacity and control of the LV network is required. This aligns with the DSO development plan. WELL has a policy for DG connections to address back feed risks, voltage issues and reverse power flow. In July 2018, EEA released the new guideline for DG connection assessment that references the latest AS/NZS standard. WELL has reviewed the latest guideline in conjunction with the re-evaluation of current application process. Once the decision on the EIPC Part 6 code change is made, WELL will update the application process and technical requirements in accordance with the new requirements.[59]

Development of the demand response market by Transpower provides incentives to building owners that have standby generation to respond to signals from the System Operator. As DG market activity increases, it is expected that the demand profile may be distorted, and there may be a need to augment network capacity to accommodate the increase in power flow from DG when it exceeds the local load and network capacity.

Enhanced control and trading platforms are also starting to enable small scale-diesel generators to participate in the market. WELL does not anticipate material disconnections with the continuing development of DG but the role of the distribution network may evolve to one where distribution control will provide hierarchical supervision of flexible DG connections.

9.7.4 Energy Storage

What it is and why it matters

Energy storage mechanisms include batteries, compressed air, pumped water and various forms of heat storage. These have the ability to increase the flexibility of a power system because they can store and release energy on demand. This section has a particular focus on batteries as these are the most readily accessible storage mechanism and the one for which the most significant technology advances are occurring. As such, batteries are the most likely form of energy storage to impact the WELL network.

[59] The DG connection policy update will ensure the new application process is still compliant with the current Part 6 of EIPC. The code is under review and WELL made submissions to the proposed EPIC Part 6 amendments.

What WELL has done so far

WELL partnered with Wellington City Council (WCC) and Contact Energy (Contact) in 2017 to trial rooftop solar power systems coupled with battery storage. One objective of the trial was to investigate whether enabling customers to run a micro grid that is islanded from the network makes Wellington more resilient.

The trial enabled Contact and WELL to control the batteries and view the meter data captured. This data included the solar output, battery state of charge and household usage. The batteries could be activated during a fault or peak demand periods to reduce loading on the network. Results from the trial confirm the effectiveness of battery storage for the targeted objectives. Other findings are that coordinated charging and discharging can benefit the network by reducing peak demand and avoid large output variations from distributed generation.

What the future holds

9.7.4.1 Batteries

The rate of installation of batteries for energy storage in Wellington is expected to rise as the unit cost for batteries falls. Installation rates will also be influenced by the results of research to improve battery capacity and capability, and as tariffs (feed-in and time-of-use charges) are refined.

The combination of increased availability of distributed storage batteries with a large EV uptake and vehicle to grid technology will have a significant impact on the network.

9.7.4.2 Hot water

Residential and commercial hot water storage systems are forms of energy storage that can be controlled via the existing ripple control system. WELL has been using this technology for a long time and, while exploring new energy storage technology, will also assess the potential of utilising hot water storage control capability for future DSO applications.

If energy storage is integrated with a DG system, it can serve as a local energy buffer (within its capacity limit) that alleviates some of the impact listed in Section 9.7.3. However, if not managed properly, storage can contribute to a higher peak and causing more issues.

9.7.4.3 Hydrogen

Another area that needs to be considered is hydrogen fuel cell technology. This technology is still at the early development stage with very limited conceptual designs available. However, hydrogen offers some unique advantages in comparison with electrochemical based storage like batteries. WELL's sister companies in Australia are currently running trial projects that involve converting surplus electricity to hydrogen, and these studies will assist WELL with future planning for alternative energy storage and options for dual energy sources.

9.7.5 Advanced Network

What is it and why it matters

Advanced networks, also known as smart grid, refers to a network made up of elements in the field and outside of the master station that:

- 'Are aware of themselves', i.e. can measure their operating parameters;

- Can communicate these parameters (including the element physical attributes) with other network elements; and
- Are controllable from local logic or from remote signals.

These elements will be required to develop a full DSO operating system.

Advanced network elements are able to adjust local load and effect network reconfiguration in response to network conditions and needs. This capability can be used to isolate faulted network sections or implement demand response. The building blocks for advanced networks include:

- Distributed energy resources (DER);
- Enhanced smart meter functions. Future smart meters should provide opportunities for a variety of applications: the ability to monitor real-time loading data, broken neutral (as a safety feature), load control, outage prediction, and dynamic pricing to enable demand side management. Most ICPs now have smart meters but these are currently only being used for one-way communication (i.e. sending information to the retailer), and the full potential of these devices is not being utilised;
- Control logic nodes (these may be integrated into the traditional primary or secondary plant) that are programmed with logic to analyse the network state and decide the next state to transition to in terms of loading and configuration;
- Controllable switches to allow for load adjustment and network reconfiguration;
- Micro grids: small sections of network that can maintain supply if disconnected from the rest of the network with autonomous voltage control and load balancing; and
- The traditional SCADA system which has visibility of the 11 kV feeders loading and switch states. The existing technology is not economically viable for a lower level smart network so the flexibility is currently limited to the main nodes on the HV network.

Most of the investment in developing advanced networks will be on the LV circuits as traditionally EDBs do not monitor LV status in real time in the same way as they do for subtransmission and distribution. The benefits of monitoring LV have traditionally not justified the costs of doing so. The accepted industry practice for LV monitoring is to investigate consumer complaints on power quality or interruptions when they occur. With an increasing number of emerging technology devices connecting to the network this approach may not be sufficient.[60]

Emerging technologies are lowering the cost of LV monitoring with functions for monitoring power flows and power quality. Monitoring all individual connection points or even all distribution transformers will be very costly to consumers. Therefore it requires WELL to understand the critical network connection points and invest wisely to keep the balance between costs and data completeness. The new monitoring systems can offer real-time data access and/or the ability to log the data locally or remotely for later download.

[60] SCADA is mostly an HV toolset (justified by the proportion of system cost compared the primary assets value) while smart metering is primarily an energy consumption device (with some in-built tools that monitor local network parameters). LV monitoring fills in the 'data vacuum' that currently exists between the SCADA and smart metering.

What WELL has done so far

WELL continues to trial LV monitoring products as they become available. Figure 9-12 and Figure 9-13 show data from a LV monitoring system that measures near-real-time data. Understanding the unique demand patterns on the LV from different customers is critical to enable the network owner to develop an energy balance system and release spare capacity to customers.

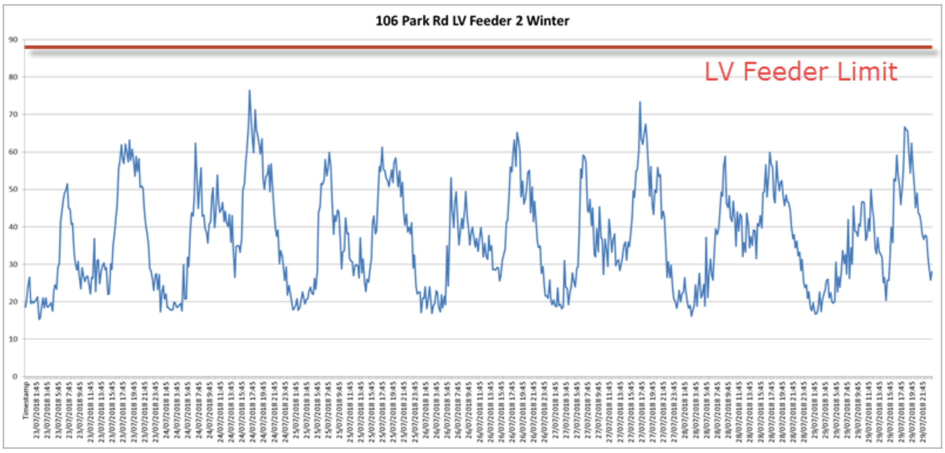


Figure 9-12 Typical Residential LV Feeder Load Profile from WELL LV Trial Projects

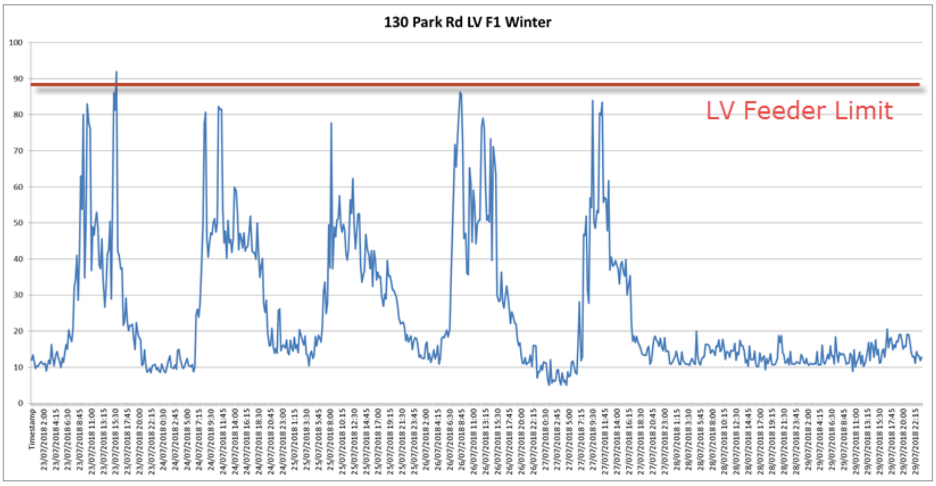


Figure 9-13 Typical Commercial LV Feeder Load Profile from WELL LV Trial Projects

In 2019 WELL expanded its LV monitoring trial to include new suppliers. Figure 9-14 shows example data from a distribution substation retrofitted with a LV monitor on its incomer.

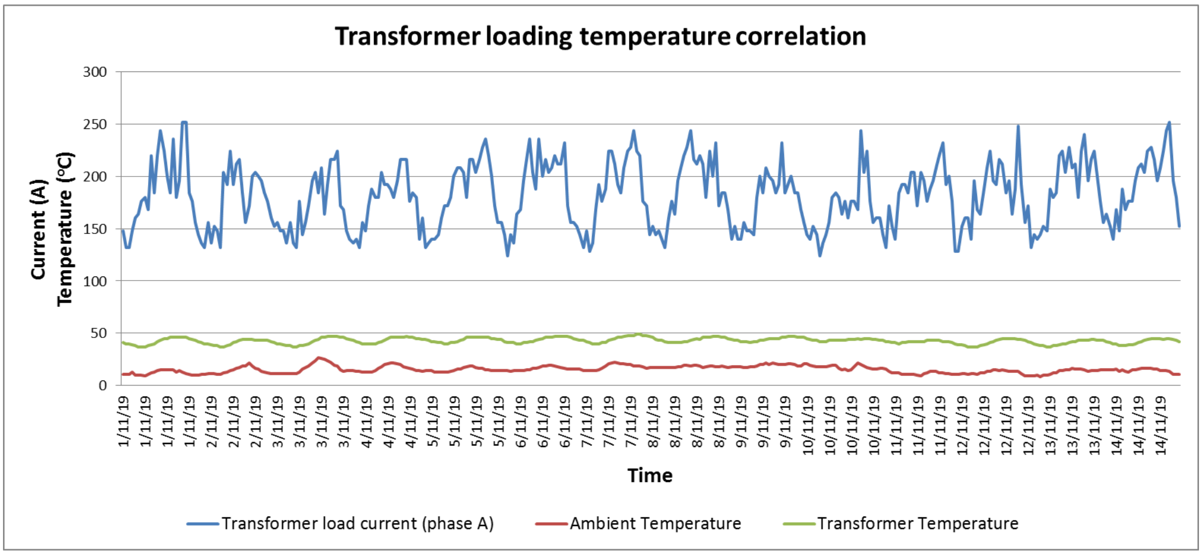


Figure 9-14 Example of Distribution Substation Monitoring

What the future holds

LV monitoring makes daily asset loading patterns visible, enabling operations and planning to optimise asset utilisation (current asset loading information is limited to the peak loading). Full visibility requires free and unobstructed access to historical and live metering data. Accurate ripple control registry information is vital to the effectiveness of ripple based load control. Ripple technology is one option for load control that can be linked to LV monitoring. Figure 9-15 shows a concept for LV monitoring and control based on LV monitoring, dispatch and ripple control.

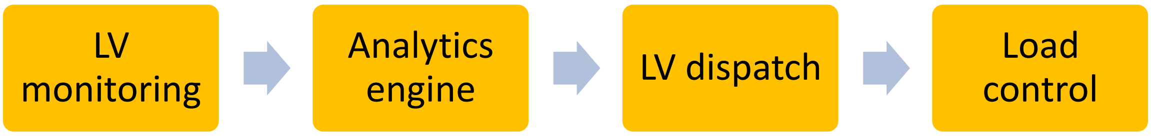


Figure 9-15 LV Network Control Concept

Opportunities for advanced network technologies include:

- Micro-grids which enable mass participation in the electricity market over a peer-to-peer trading platform. The key to an effective peer-to-peer trading platform is the right people getting paid at the right time with the right amount. This will also require information system technology improvements to enable the trading platform utilising blockchain technology which can then enable community energy trading in microgrids;

- Reduced durations of low demand period and high durations of peak demand periods implies reduced outage windows, leading to more complicated outage planning if traditional outage planning approaches are used. By leveraging smart networks to create outage windows when they are needed and by controlling distributed generation and flexible loads, the complexity and risk of maintenance outages could be reduced; and

- Advanced Metering Infrastructure coupled with the “Internet of Things” (referred to as IoT for consumers’ devices and IIoT for industrial machines) provides a platform for automated load response to network conditions and may lead to a greater focus on network resilience (as opposed to reliability). This is due to appliances/industrial machines having logic to understand local processes and energy needs and therefore being able to automatically moderate the amount of power drawn by the household/industrial plant.

With advanced networks, assets can be designed and operated on the basis that outages will not interrupt supply if services can be restored before batteries are depleted. This supports a change in priorities from planning for redundancy and achieving very low failure rates in our network to ensuring more rapid supply restoration; shifting the emphasis from reliability to resilience.

The advanced networks development plan will include both primary and secondary assets. WELL's initial focus will be on developing a knowledge base through small scale trials to evolve the network into a smarter network.

9.7.6 Energy Efficiency

What it is and why it matters

Initiatives for energy efficiency involve approaches that increase demand on the electricity network (such as switching from other energy sources to electricity e.g., heat pumps displacing log burners) and other approaches that reduce the demand (such as adopting energy efficient appliances). More efficient appliances reduce energy consumption and can often be set to respond to network pricing signals.

Initiatives undertaken by the EECA are raising the awareness of consumers about improvements in energy efficiency. This is expected to result in demand pattern changes and WELL will be tracking the net impact of these changes.

What the future holds

Figure 3-7 shows the Wellington network energy consumption trend which has stabilised after recent years of decline. To understand the trend WELL needs to:

- Improve understanding of drivers for network losses, continue to refine the loss factor calculation model and collect more information;
- Study the impact of DER penetration on network efficiency. DERs are likely to reduce the overall technical loss as less volume of energy is transferred from the GXP;
- Understand how appliances with better efficiency will assist in lowering energy use, reduce peak demand and assist in peak loading control; and
- Help consumers understand energy conservation and how to save energy.

Some of the energy efficiency initiatives that will impact the network include:

- Heating: electric heaters and heat pump technology replacing coal for industrial process heat (increasing demand) and heat preservation such as insulation and heat recovery (reduce demand);
- Lighting: the local authorities in the WELL network area have started adopting energy efficient street lights and WCC has observed 66% energy saving on their trial installations[61];

[61] https://wellington.govt.nz/~/media/your-council/meetings/committees/transport-and-urban–development-committee/2014/08/report8attachment1.pdf

- Systems optimisation through recalibrating existing equipment which can lead to a reduction in energy consumption (e.g. air-conditioning, process speed, etc.); and
- Energy management/process optimisation, (e.g. controlled cold store access or machine running sequence optimisation).

Transport electrification is another key area of improvement in energy efficiency and is discussed separately in Section 9.7.2.

The energy efficiency development plan will focus on operational practices, processes and policies to encourage and support adoption of energy efficient equipment.

9.7.7 Master Station and Real-time Technology

What it is and why it matters

Network real-time technology refers to secondary systems that enable a network operator to view the network from a central point and automate protection, control and communications functions, i.e. collect information on system state and execute operational actions (switching or changing set points) at the instance the decision point is reached (real-time). The master station is a core component of real-time technology that is in a centralised location and providing interface to a smart network.

The objectives of network real-time technology include safe network operation, increased reliability and improved asset utilisation. The technologies include Supervisory Control and Data Acquisition (SCADA), Distribution Management System (DMS), Outage Management System (OMS), Work Order Management (WOM), Field Mobility Dispatcher (Mobile switching), Energy Management System (EMS), and Power Control System (PCS). An advanced distribution management system (ADMS) integrates these features into a single solution.

What WELL has done so far

WELL is currently using a GE PowerOn Fusion network DMS and OMS that supports the achievement of safe, secure, efficient network operations through:

- Automated workflows that have increased operational efficiency since adoption of the solution;
- Full HV network visibility through SCADA and hand-dressing functions to improve situational awareness; and
- Increased proportion of live equipment switching done through SCADA, which minimises staff exposure to dangerous voltages therefore improving safety.

The GIS holds asset details of the HV and LV networks. Asset location information from GIS is used in combination with real-time system information from SCADA supports planning and rapid response to outages. This has resulted in more efficient day to day business operations.

What the future holds

Network real-time technology provides the platform for building smart network solutions. The market now offers integrated solutions that include:

- SCADA for real-time network visualization and a network analysis platform;

- OMS incorporating mobile workforce management (MWFM) for improving outage response and restoration times;
- Fault detection, isolation and restoration (FDIR) using pre-programmed automated switching sequences to maintain supply and minimise impact of faults;
- EMS for DER control;
- An integrated network model for design, planning, protection, reliability studies and operations;
- Standardisation with most industry applications and easy integration with legacy and third party software; and
- Advanced analytics[62] to inform operators of the impact of load and generation scenarios (such as system constraints) ahead of real-time, and for configuring other automation subsystems (such as alarm levels, automated switching sequences).

The network real-time technologies function over a communications platform that may be one, or a hybrid, of traditional RTU driven point-to-point systems, multi-cast radio and/or segregated secure tunnel via public wireless data network. The master station and real-time technology development plan outlines WELL strategies for network real-time technology and the development of the necessary capability to transition to a DSO.

9.7.8 Digitisation and Data Transformation

What it is and why it matters

DERs and advanced networks demand new capabilities and trigger the need for new data-driven business models and regulatory frameworks. Digitisation enables a process to be fundamentally reconfigured, for example, combining automated decision making with self-service can eliminate manual processes. This will be a fundamental element to providing an effective DSO platform.

WELL's existing asset base is made up of a combination of legacy assets from the pre-digital age and recent additions to the network that are digitally enabled (for example, switchgear with digital interfaces, numeric protection relays, and IP based communication links to key sites). With current levels of digitisation WELL can only exploit a limited proportion of the device capabilities until full digital integration can be realised.

What the future holds

Currently WELL's asset base has a significant portion of legacy, digitally incapable assets and limited industry knowledge to learn from. The future approach will be a hybrid of being an 'industry leader' for aspects that it is better placed to develop knowledge on and a 'smart follower' to learn from the experience of others.

The smart devices on the network, network remote control and automation systems (working on digital computing and communications platforms), allow for real-time operation of the network and its connected

[62] Advanced Analytics includes Distribution State Estimation, Volt/VAR Optimization (VVO), Conservative Voltage Reduction (CVR), Fault Location, Isolation & Service Restoration (FLISR), Outage Prediction, Load Forecasting, Unified AC & DC Power Flow, Distributed Generation Modelling, Protection, Load Shedding, etc.

resources, and the collection of network data to improve situational awareness and services. Current market developments include:

- Technology firms with internet based services are redefining consumer expectations. Customers are coming to expect a similar level of flexibility and responsiveness from all other service providers; and
- A wealth of meter data from the advanced metering assets. This data is currently owned by the meter providers and open access will enable network operators to utilise the information. It is envisaged that access should be a commercial arrangement between network operators and the retailers.

Challenges for adoption of digital technologies include:

- Regulation and tariffs more suited to the existing network and business models;
- Legal frameworks to provide access to customer data from the smart meters;
- A significant proportion of corporate knowledge is still in non-digital form and needs to be transformed into data formats that support enhanced analytics; and
- Cyber security and data confidentiality, integrity and availability.

Data collection and exchange is growing rapidly, creating both digital threats and opportunities. Digitisation alters the capabilities and tools that a network operator needs to succeed. It greatly lowers barriers to market entry for competitors that do not traditionally participate in the electricity market, and is also a catalyst for raising customer expectations around products and services not previously offered by utility companies.

Network opportunities unlocked by digitisation include:

- Continuous refinement of network usage patterns. Smart meters provide energy suppliers with the exact details of each customer's generation and consumption from which tailored products can be developed;
- Productivity tools for employees that support enhanced workflow management, e.g. field workforce access to maps, asset data, work management tools and real-time expertise; and
- Back office automation and data-driven decision making. This includes: data-driven asset strategies such as preventive and condition-based maintenance, and the ability to plan confidently for transformative enhancements in reliability, safety, customer experience, compliance, and revenue management.

Successful digital transformations also benefit from:

- A cultural shift from the traditional investment in expensive long-life assets to a state where success depends on exploiting new capabilities driven by rapid scaling of innovations; and
- An organisational structure with supporting governance principles and a change management strategy that offers room for digital innovation.

The digitisation and data transformation development plan identifies the IT technology required to host new software, application and storage development.

9.8 Summary of Emerging Technology Investment Plan

Emerging technologies will continually present opportunities and challenges that require WELL to evolve. To ready the network and the organisation for a future enabled by emerging technologies, WELL will implement strategies to keep abreast of emerging technology. WELL will increase its research and trials, as outlined in the emerging technology development plans above, to gain sufficient knowledge on the impact and potential of these technologies. The regulatory and commercial frameworks will need to evolve in order to support the rapid changes.

The AMP over the next 2–3 years has a strong focus on research and development to test new technology and to develop a business plan of the future DSO. The following 5–10 year period will then begin to deliver that business plan.

Where necessary WELL will lean on industry collaboration to draw useful learnings from the experience of others. WELL will identify innovation partners and work with them to develop the proof of concepts and actively participate in industry forums to share what we have learned.

Figure 9-16 shows the spread of investments over the next 10 years required to assess the impact of emerging technologies.

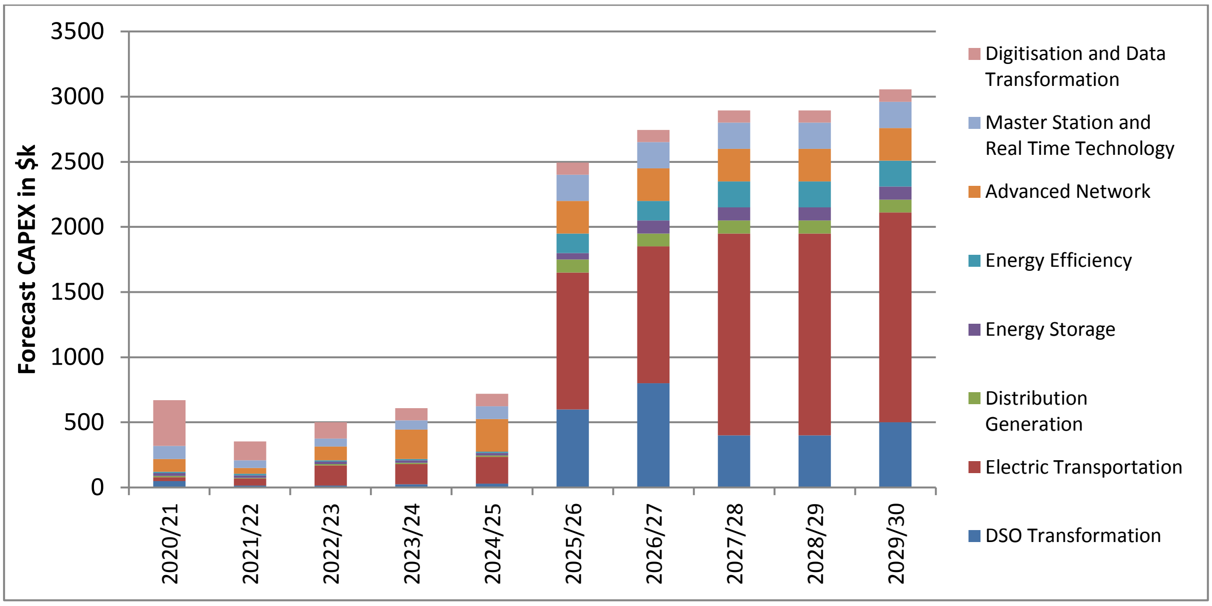


Figure 9-16 Spread of Investment in Emerging Technologies

The total capital expenditure forecast for the emerging technology related development plan over the next 10 years is shown in Table 9-1.

Expenditure Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
DSO Transformation	50	15	15	25	30	600	800	400	400	500
Electric Transportation	30	55	155	155	205	1,050	1,050	1,550	1,550	1,610
Distribution Generation	10	5	10	10	10	100	100	100	100	100
Energy Storage	20	20	20	20	20	50	100	100	100	100
Energy Efficiency	10	10	10	10	10	150	150	200	200	200
Advanced Network	100	45	105	225	250	250	250	250	250	250
Master Station and Real Time Technology	100	60	60	70	100	200	200	200	200	200
Digitisation and Data Transformation	350	145	125	95	95	95	95	95	95	95
Capital Expenditure Total	**670**	**355**	**500**	**610**	**720**	**2,495**	**2,745**	**2,895**	**2,895**	**3,055**

Table 9-1 Capex Forecast Summary (Emerging Technologies Development Plans) ($K in constant prices)

Section 10

Support Systems

10 Support Systems

WELL invests in non-network assets to support the distribution of electricity to customers. These assets include information systems, plant and machinery, and land and buildings. This section describes the approach taken and the investment requirements for these systems over the planning period.

10.1 WELL Information Systems

The following information describes the key repositories of asset data used in the asset management process, the type of data held, 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.

Table 10-1 shows where asset information is stored within WELL's systems.

	Physical Assets	Equipment Ratings	Asset Condition	Connectivity	Customer Service	Financial Management
Supervisory Control & Data Acquisition (SCADA)		✓		✓	✓	
Geographical Information Systems (GIS)	✓	✓		✓	✓	
Drawing Management System	✓	✓			✓	
Power Systems Modelling		✓		✓		
Protection Relay Configuration Management System	✓	✓				
Maintenance Management System	✓		✓		✓	
Billing System				✓	✓	
Financial System						✓

Table 10-1 Asset Data Repositories

10.1.1 Asset Information and Operational Systems

The information systems WELL uses to manage its asset information are described below.

10.1.1.1 SCADA

A GE PowerOn Fusion Supervisory Control and Data Acquisition (SCADA) system is used for real time operational management of the WELL network. The SCADA system provides operation, monitoring and control of the network at 33 kV and 11 kV. WELL does not have any telemetry feeding the SCADA system for the low voltage (LV) network (400 volts or below) but is investigating how this could be implemented as distribution substations are upgraded or replaced. In addition to this, with advances in GIS technology investigations are underway to identify how to develop LV switching schematics from the GIS. Outage reports are recorded by the GE PowerOn Fusion Calltaker system utilised by the Outage Manager at the WELL Contact Centre. The Calltaker system electronically interfaces with the field service provider's dispatch system to dispatch field staff for fault response.

WELL is planning to upgrade its SCADA from PowerOn Fusion to GE's PowerOn Advantage product, which will provide:

- A New Zealand standardised distribution symbol set;
- A more flexible and resilient IT architecture utilising virtual machines and e-front ends;
- Integration with GIS via common information model adaptor so that LV models can be imported; and
- An upgrade of workstation and server hardware to latest supported hardware and operating systems.

WELL is also currently investigating the upgrade options for two other systems related to SCADA:

- **Historian**: WELL currently uses TrendSCADA which is a proprietary data historian tool interfaced 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 EDBs and which may offer greater benefits to the business and improve user-friendliness; and
- **Load Management**: WELL currently controls load using the Foxboro SCADA system. This system is currently at the end of its economic life and is due for replacement in 2021.

10.1.1.2 Geographic Information System (GIS)

The GIS provides a representation of the system's fixed assets overlaid on a map of the supply area. WELL 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 interfaces to WELL's maintenance management system (SAP PM), the billing system (Gentrack), and the field service provider's works management system.

WELL is planning to replace the existing GIS with a newer version which provides better system performance, data quality assurance tools, and improved user functionality. This is likely to be the GE Electric Office suite that provides improved functionality and ongoing minor upgrades rather than the "big bang" approach. Electric Office has been assessed independently as the best long term technology fit for WELL, especially as greater integration becomes required between GIS and SCADA in future.

10.1.1.3 Drawing Management System

WELL stores all GXP, substation, system drawings, and historic asset information diagrams in ProjectWise in PDF and CAD format. This system will be upgraded in 2025.

10.1.1.4 Power System Modelling

The DigSILENT PowerFactory is used to model and simulate the electrical distribution network and analyse load flows for development planning, contingency planning, and protection studies. The PowerFactory 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.

10.1.1.5 Cable Rating Modelling

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.

10.1.1.6 LV Voltage Drop Modelling

LVDrop is used to model LV electrical networks to ascertain voltage drops and loading of conductors and transformers. LVDrop contains all the relevant 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.

10.1.1.7 Protection Relay Configuration Management Database

DigSILENT StationWare is a centralised protection setting database and device management tool. It holds relay and device information, parameters and settings files. StationWare is accessible remotely, via the Citrix environment, to allow input and modification by approved design consultants. Protection settings are uploaded to the StationWare database for review and approval. The settings are then distributed to commissioning personnel for application in the field.

10.1.1.8 Maintenance Management System

WELL uses the SAP Plant Maintenance (SAP PM) module to plan its maintenance activities and capture asset condition data for both preventative and corrective works. This system allows WELL to issue maintenance workpacks to service providers electronically. Maintenance results are returned electronically via either an integration module (for high volume tasks), or a web interface (for low volume tasks). Asset data is synchronised with GIS, which allows maintenance tasks to be grouped spatially to increase efficiency.

SAP PM is currently hosted in Melbourne by WELL’s sister company Powercor and is an aged version. WELL will be investigating if SAP PM is the best platform for maintenance management in the future, and plans to commence an investigating into options for replacement. This investigation will also consider options for replacement of the SAP Portal which is also used as a customer facing system.

10.1.2 Billing System

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.

The current Gentrack system is hosted in Melbourne by WELL's sister company Powercor. WELL is exploring either hosting this application itself or taking a cloud service from Gentrack or other billing systems vendor.

10.1.3 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.

SAP is currently hosted in Melbourne by WELL's sister company Powercor and is an aged version. WELL will be investigating if SAP financials is the best platform for financial management in the future and plans to commence an investigating into options for replacement.

10.1.4 Cyber Security

WELL is facing increased cyber security threats in the same manner as all critical infrastructure providers. WELL is working closely with the National Cyber Security Centre (NCSC) to ensure that its IT systems, especially those relating to the direct control of the electricity network, are as secure as possible. This increased cyber risk means that WELL needs to invest more heavily in IT systems and processes that enhance cyber security monitoring and protection.

10.2 Identifying Asset Management Data Requirements

Asset management data requirements are defined in WELL's asset maintenance standards. The asset management data requirements are 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 asset information into the GIS and SAP PM information systems.

10.3 Data Quality

Robust and timely asset information is needed to drive asset management activities such as development, maintenance, refurbishment and replacement. As the GIS system is the central repository for WELL'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. 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, WELL 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. Table 10-2 lists areas where risks have been identified due to gaps 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 are 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
PowerFactory	Historical network augmentations or customer connections may not be captured in the model	Engineering Planning team updates 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 reflect actual state
StationWare	Not all station protection relay settings have been captured in StationWare	Settings are updated at the time of projects being undertaken, or 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	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.

Table 10-2 Overview of Asset Data Gaps and Improvements

Data management and governance is becoming more critical for WELL as the distribution network business evolves. WELL has identified a need to review its data management as it is aware that there are data quality issues within its business and operational systems. WELL has therefore commissioned a detailed study by a data management expert. The outcome of this investigation will provide a forward plan for data management within the business.

10.4 Information Systems Plan

WELL assesses its network support information systems to ensure the software and supporting hardware is supported and continues to meet its asset management data requirements. The major planned changes in network support information systems over the next five years are shown in Table 10-3. These are separate to the SCPP discussed in Section 11.

System	Change & Year	Benefit	Cost ($K)
GIS	Upgrade to Electric Office version in 2020-21. Ongoing minor upgrades 2021 to 2029.	Supportability, Improved Functionality and IT security	1,530
Corporate Office Equipment	Email, Desktop, Meeting Rooms, Safety Website 2020-30	Improve functionality, Routine replacements	1,200
SAP Finance	2024-25 staged upgrade	Potential cost saving and process efficiency	1,500
SAP PM	2022-25 Upgrade to either cloud based or WELL hosted fit for purpose system	Potential cost saving and process efficiency	1,500
Gentrack	2022-26 Staged upgrade to either cloud based or WELL hosted fit for purpose system	Potential cost saving and process efficiency	2,000
SAP HR	2025 Upgrade to either cloud based or WELL hosted fit for purpose system	Potential cost saving and process efficiency	250
Drawing Management System	2025 Upgrade to latest supported version	Supportability and IT security	200
Corporate WAN/LAN	2026 Refresh core routing and switching equipment	Supportability and IT security	600
Telephony	2025 Refresh of IP telephony hardware	Supportability and IT security	350
Datacentres (incl. corporate servers)	2026-29 Refresh core IT infrastructure racking and equipment	Supportability and IT security	2,900
Cybersecurity	2020-30 Implement overall IT/OT security monitoring platform	IT security	1,000
PowerOn Advantage V6.X	New ADMS Platform (2021/22 and upgrade in 2028/29)	Existing version will be no longer supported by the Vendor, new platform with functional enhancements, user experience and third party software interface	2500
Load Control Master Station	Replacement Foxboro Master Station (2021-22)	Replacement of legacy master station, improve functionality and enable modern platform interface	715
Power Factory DigSILENT	Upgrade 2022	Additional licence, improve functionality, user experience and system stability	50
LV Drop	Upgrade 2022	Improve functionality and model accuracy	50

Table 10-3 Overview of Major System Improvements

10.5 Plant and Machinery Assets

Vehicles are typically replaced every three years in accordance with WELL's Motor Vehicle Policy. Other test equipment and tools are replaced as required, for example power quality measurement devices and partial discharge test sets. There are no other material investments planned for non-network plant and machinery.

10.6 Land and Building Assets

WELL 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.

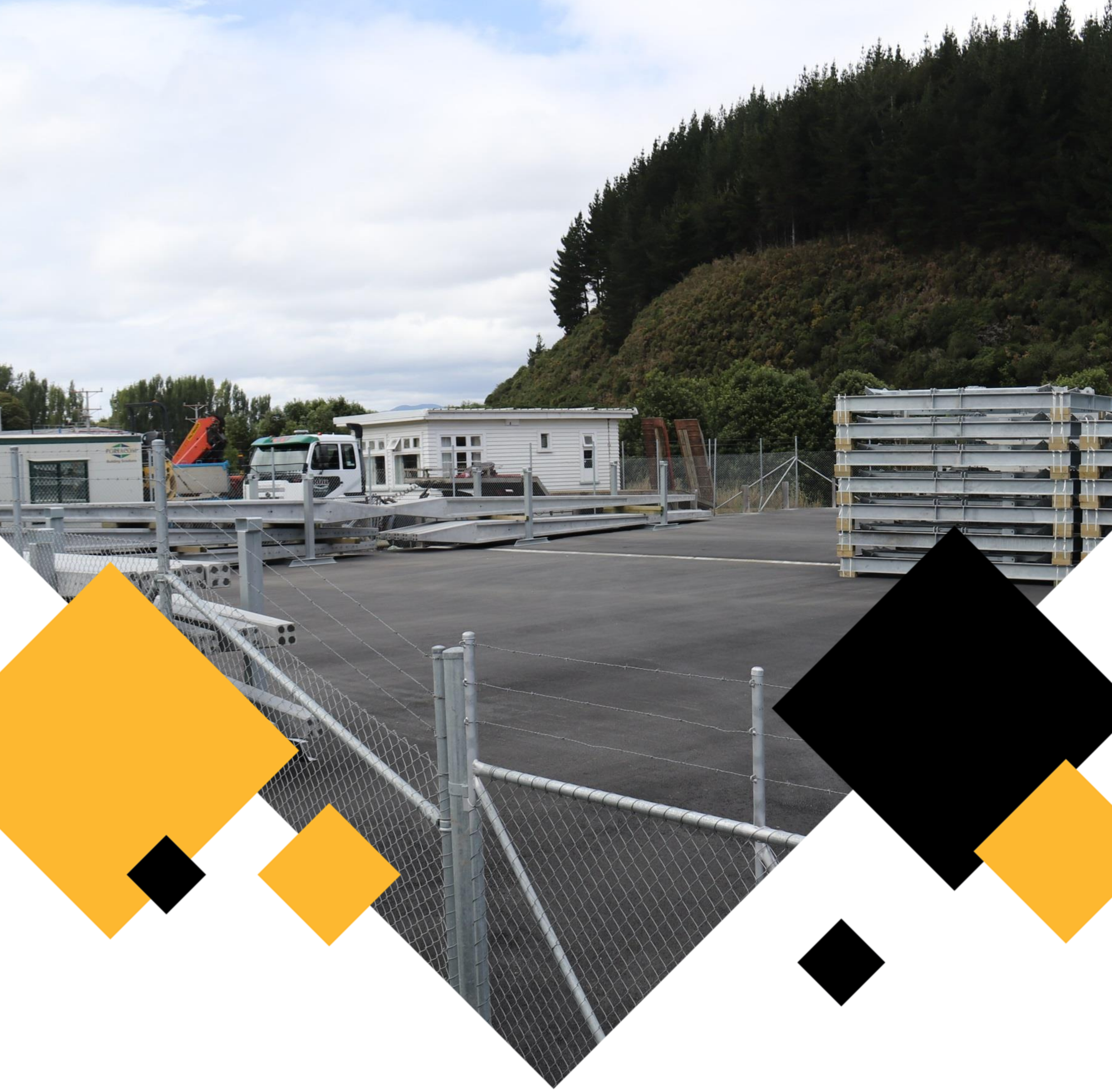
The capitalised lease capex item relates to the new accounting standard that now treats operating leases as a capital item. The capitalised lease items mainly relate to leased vehicles.

10.7 Non-Network Asset Expenditure Forecast

From the details in the sections above, WELL's non-network expenditure forecast is summarised in Table 10-4.

Routine Expenditure	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Software and Licenses	650	1,214	1,219	1,025	911	1,286	1,499	1,130	1,173	795
IT Infrastructure	570	521	551	455	449	634	738	557	578	392
Capitalised Leases	-	-	-	-	790	-	-	-	-	-
Streamlined CPP	3,450	-	-	-	-	-	-	-	-	-
Total Non-network CAPEX	**4,670**	**1,735**	**1,770**	**1,480**	**2,150**	**1,920**	**2,237**	**1,687**	**1,750**	**1,187**
System Operations and Network Support	7,097	7,097	7,097	7,097	7,097	7,097	7,097	7,097	7,097	7,097
Business Support	11,493	11,493	11,493	11,493	11,493	11,493	11,493	11,493	11,493	11,493
Total Non-network OPEX	**18,590**	**18,590**	**18,590**	**18,590**	**18,590**	**18,590**	**18,590**	**18,590**	**18,590**	**18,590**

Table 10-4 Non-Network Expenditure Forecast ($K in constant prices)



Section 11

Resilience

11 Resilience

11.1 WELL's Resilience Framework

This section describes WELL's approach and investment plan relating to resilience and focuses mainly on managing and mitigating events beyond normal circumstances and under emergency situations.

As a lifeline utility in accordance with the CDEM Act, WELL must ensure that it is able to function to the fullest possible extent during and after an emergency, even though this may be at a reduced capacity. This can include one-off events such as a storm, earthquake, or equipment failure. A concern for WELL is that currently the existing avenue of funding via the DPP allowances does not fully cater for resilience funding. This was shown by WELL needing to make a SCPP application to address earthquake readiness following the 2016 Kaikoura earthquake. This was in response to the Government Policy Statement of 21 September 2017, and was approved by the Commission in March 2018.

The WELL resilience framework has been sectionalised in this plan per the following structure:

- Climate change;
- Emergency response and contingency planning;
- High impact low probability (HILP) events;
- Earthquake readiness SCPP application; and
- Future resilience work – WeLG Regional Resilience Project.

There is significant work underway to be earthquake ready. Delivery of the SCPP is progressing well and will improve WELL's ability to respond in an emergency. It is important to note that the focus of the SCPP programme is improving emergency response and while it does provide some resilience improvements, further work is needed to ensure the network can withstand a major earthquake. Section 11.6 discusses additional work that could be delivered to further improve resiliency, including improving the single point of failure risk at Transpower's Central Park substation and speeding up the replacement of fluid and gas-filled subtransmission cables. Both these changes need to be discussed with wider stakeholders to agree whether the extra costs required should be spent to improve resiliency.

WELL remains concerned that a major event could damage the network, causing outages and extensive repairs similar to those faced by Orion in the 2010 and 2011 Canterbury earthquakes.

From a regulatory perspective, WELL is concerned about the level of risk that is borne by the EDB and whether an EDB will have the funding available at the time when it is needed to repair the network. WELL's concerns include:

- High insurance premiums mean that only a small proportion of assets can be sensibly insured. The majority of the network assets are uninsured and their replacement after a natural event would need to be funded by a price increase;

- Although the full cost of repairs can be recovered by price increases, these are limited to a 10% increase per annum. An EDB may not have the cash at the time when essential network repairs are needed;
- If revenue collected falls below 80% (which is possible after a natural event as services could be inoperable for a period), then under the current regulatory rules, a proportion of that revenue becomes unrecoverable, reducing an EDB's cash flow needed for essential repairs even further; and
- Regulatory allowances do not recognise that some regions in New Zealand are more exposed to the risk of a natural event. EDBs in high risk areas do not have additional funding that they could use in an emergency to repair their network.

WELL will continue to discuss these concerns with the Commission.

11.2 Climate Change

Climate change is expected to cause a rise in sea levels as well as changing weather patterns which may result in more frequent and severe storms than have previously been experienced in the region. This will impact temperature, rainfall and wind within the region as well as the frequency and intensity of storms.

The average temperature in the region is expected to increase by 0.7-1.1°C by 2040 and could increase by up to 3°C by 2090.[63] Rainfall is expected to vary locally within the region as well as seasonally. Latest projections do not show an increase in the frequency of storms greater than the current inter-annual variation; however the intensity of these storms may increase. It is expected that more high wind days will be experienced which will require continuing efforts to manage the reliability of overhead lines and vegetation.

Rising sea levels present a risk in central Wellington where a large number of substations in the CBD are in the basements of buildings. The sea level at Wellington rose at an average of 2.79 mm per year from 1961 to 2018, through a combination of climate factors and seismic subsidence, with the rate of rise continuing to accelerate.[64]

Sea level rise is a long term problem, with significant variations in possible scenarios, and effects becoming significant towards the end of the century.[65] Issues could occur sooner, with stronger storms due to warmer seas creating larger storm surges on top of rising sea levels, such as was witnessed during Hurricane Sandy in 2012, and Cyclones Fehi and Gita in 2018.

A co-ordinated response between local authorities and utilities is required to prepare the region for the impacts of climate change. WELL is making changes to policies and standards to better protect the network from these risks. For example, a storm inundation policy has been written that over time will better protect assets at risk of storm inundation. To be effective, these changes in standards cannot be made in isolation. Further work with local authorities is required to understand their defence strategies, and to influence District Plan updates, to ensure that WELL's policies and standards are tightly aligned to a coherent plan across the Lifelines Group.

[63] "Wellington Region climate change projections and impacts" NIWA, June 2017.

[64] "Update to 2018 of the annual MSL series and trends around New Zealand" NIWA, November 2018.

[65] "Sea Level Rise Options Analysis" Tonkin & Taylor, June 2013.

11.3 Emergency Response and Contingency Planning

WELL applies the following strategies to mitigate the impact of potential 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 further investment in resilience (subject to additional funding being made available);
- **Readiness** – reduce the impact of an HILP event where appropriate, by improving network resilience (subject to additional funding being made available);
- **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 mitigation of potential HILP events is supported by a number of plans and initiatives across the business described in the following sections.

11.3.1 Civil Defence

The Ministry of Civil Defence and Emergency Management (MCDEM) is responsible for emergency management on a national scale. Emergency management is governed through the Civil Defence Emergency Management (CDEM) Act 2002 which sets out the requirements for each resilience group, including local Emergency Management groups, Lifeline Utilities and Emergency Services as well as producing and maintaining the national components of the CDEM framework.

11.3.2 Wellington Regional Emergency Management Office (WREMO)

The Wellington Regional Emergency Management Office (WREMO) was formed in 2012 and is a semi-autonomous organisation that coordinates civil defence and emergency management services on behalf of the councils in the Wellington region. While there is not an emergency response the emergency management office concentrates on identifying potential local hazards and implementing measures to reduce risks as well as promoting awareness of these risks and assisting other regional groups when this is requested.

11.3.3 Wellington Lifelines Group (WeLG)

The Wellington Lifelines Group is a working group comprised of the lifeline utilities operating within the region and representatives from local and regional government. Lifeline utilities are defined by the CDEM Act as businesses providing essential services to the community including:

- Transport infrastructure (road, sea and air);
- Water supply and reticulation systems;
- Sewerage and storm water drainage systems;
- Electricity transmission, generation and distribution networks; and

- Telecommunications network providers.

WELL is classified as a Lifeline Utility under the CDEM Act and as such has the following responsibilities:

- Ensuring it is able to function to the fullest possible extent even though this may be at a reduced level during and after an emergency;
- Having a plan for functioning during and after an emergency;
- Participation in CDEM strategic planning; and
- Providing technical advice on CDEM where required.

The CDEM Amendment Act 2016 places additional emphasis on ensuring that lifeline utilities provide continuity of operation where their service supports essential emergency response activities.

In November 2012 WeLG published a report on the likely restoration times for lifeline utilities based on the scenario of a magnitude 7.5 earthquake on the Wellington fault, centred in the harbour area. This report was partly in response to questions arising after the Christchurch earthquakes as to how Wellington would fare in a similar event. The report set out the time required after an event for each lifeline utility to restore services to a defined level in different areas around the region. Dependencies between utilities were not accounted for but these were often mentioned among the assumptions. A key difference identified in the report between the Canterbury and Wellington regions was the number and vulnerability of transport access routes in the Wellington region and the extensive recovery times anticipated. It is expected that some of this will be alleviated by the Transmission Gully route which is currently under construction.

Through 2018 and 2019 WeLG conducted a project on regional disaster response and recovery, as discussed in Section 11.6. A key component of this project was consideration of the interdependencies between lifeline utilities and how these are likely to affect the restoration process. This project involved detailed modelling of the likely damage to each lifeline utility network based on GNS modelling of the Wellington fault and regional geography as well as the economic impact on the region that such an earthquake would have.

11.3.4 WELL Contingency Plans

To comply with the responsibilities as a lifeline utility as set out in the CDEM Act, WELL has created a number of plans detailing the actions to be taken in a range of situations.

11.3.4.1 Emergency Response Plans (ERPs)

As part of the Business Continuity Framework Policy, WELL has a number of ERPs to cover emergency and high business impact situations. The ERPs require 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.

11.3.4.2 Civil Defence and Emergency Management (CDEM) Plan

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

This CDEM Plan follows the four 'Rs' approach to dealing with hazards that could give rise to a civil defence emergency.

11.3.4.3 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.

11.3.4.4 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.

11.3.4.5 Business Recovery Management Plan (BRMP)

The BRMP covers, any event that interrupts the occupancy of WELL'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 WELL 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.

This plan was put into practice after the November 2016 earthquake which rendered the corporate office in Petone unsafe to conduct business from, and required all corporate business functions to relocate to Haywards substation and operate from there until the end of January 2017.

11.3.4.6 Information Technology Recovery Plan (ITRP)

The ITRP is in place so that WELL'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.

11.3.4.7 Major Event Field Response Plan (MEFRP)

The MEFRP covers WELL's field contractors so they are prepared for, and can respond appropriately to, a HILP event. The MEFRP designates actions required and responsibilities of WELL 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.

11.3.4.8 Emergency Evacuation Plan (EEP)

The purpose of the EEP is to ensure that the Network Control Room (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. This plan was also utilised after the November 2016 earthquake which rendered the corporate office in Petone unsafe and required all corporate business functions to relocate to Haywards.

11.3.4.9 Earthquake Response Plan

The purpose of the Earthquake Response Plan is to ensure that WELL is prepared to respond safely and effectively to an earthquake that impacts the electricity network, with consideration for the probable isolation between different network areas. This involves direction on how and when to activate other associated event management plans as well as directions for use of the DR sites and access to earthquake specific equipment and systems including:

- PAlert warning system and shakemap;
- Safe building entry;
- Emergency spares locations and access; and
- Mobile substations and data centres.

11.3.4.10 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.

11.3.4.11 Other Emergency Response Plans

WELL 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.

11.4 High Impact Low Probability (HILP) Events

The WELL network is designed with a certain amount of security and reliability built into it to account for isolated equipment failures and regularly occurring adverse events. However, as with all infrastructure, the network is susceptible to potential HILP events which could cause a major unplanned outage for a prolonged period.

Due to the geography of the region and weather patterns, the Wellington region is at risk from both earthquakes and severe storms, with earthquakes having the most potential to cause widespread damage throughout the region. Other possible HILP events include an upstream supply failure, communications failure, cyber security breach or information security breach or loss.

HILP events are unpredictable, generally uncontrollable and prohibitively expensive to avoid, if at all possible. WELL's design standards align with industry best practice and take the weather and seismic environment of the region into account. These design standards do not however cater for weather conditions or seismic events that are beyond what is deemed 'normal' for the region.

WELL's management of unforeseen events is split into two areas, mitigation of the risk through network planning, design and asset maintenance and then response during and after an event to restore power quickly without compromising contractor or public safety.

11.4.1 Identification and Planning for HILP Events

Some of the methods used by WELL to identify HILP events are:

- **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 have been undertaken on behalf of WELL by GNS and other external providers.

11.4.2 Strategies to Mitigate the Impact of HILP Events

A discussion on the following HILP events is covered below:

- Major storm events;
- High impact asset failure;
- Upstream supply failure; and
- Major earthquake.

11.4.2.1 Major Storm Events

The Wellington region is very susceptible to high winds and severe storms, which have the potential to cause a significant amount of widespread damage to the overhead network. For this reason WELL uses a relatively high wind loading when designing overhead lines when compared with other network companies.

This susceptibility is also a factor in the high proportion of the Wellington network that has been constructed with underground cables.

A major risk of potential outages on overhead sections of the WELL network is lines being struck by vegetation and windblown debris. This is currently managed via the WELL vegetation programme which, as discussed in Section 6.5, has been successful in maintaining the reliability of the network. It can be difficult to protect against strong wind gusts causing vegetation to contact lines that do not normally get close to a line, or where debris has been blown clear of the line before a patrol can be completed.

In June 2013, Wellington experienced a severe storm of a magnitude similar to the "Wahine" storm of 1968. Wind gust speed remained above 100km/h for approximately 24 hours, peaking at over 200km/h. The storm caused significant damage to the WELL network and at its peak resulted in 30,000 homes and businesses being without power. Damage to network assets affected customers in both rural and urban areas with wind gusts uprooting trees and carrying debris into overhead lines, damaging poles and conductors.

The affected areas were widespread and outages were prolonged as the conditions made it difficult to patrol and repair lines. Blocked roads and traffic congestion resulted in travel time delays. To address the significant workload, 150 additional staff from other regions were brought in to assist with the restoration efforts.

In addition to causing widespread damage in the overhead network, major storms can result in flooding in many parts of the region. While this does not cause the same widespread network damage there are some locations where a flood could lead to significant damage and network disruption.

11.4.2.2 High Impact Asset Failure

WELL network's system security standard is designed to provide a security of N-1 at zone substation level, meaning that each zone can operate at full capacity after the failure of a single asset. This is generally achieved by having dual subtransmission circuits and power transformers. Resilience within the 11 kV network is provided by the use of meshed rings or tie points between radial feeders to minimise the effect of equipment failure and improve the restoration after an event.

Due to the constrained nature of many WELL sites and the subtransmission routes that have been constructed sharing the same route, an event affecting one component has the potential to affect the other and lead to a total outage at that site. This is mitigated through different means depending on the type of asset, such as physical barriers between transformers at some sites, or separation between overhead lines where space allows.

Where an event leads to a total loss of supply at a zone substation, it is generally possible to restore the majority of the load through network switching to supply the area from a different zone substation. However this is not possible for all substations or at all times in the year. Higher loadings, or substations located at the extremities of the network and without strong ties to other zones, result in areas that are unable to be supplied in the event of a total zone substation outage.

Areas that are unable to be supplied in the event of a zone substation outage are mostly at the extreme ends of the network with Wainuiomata, Karori, Mana-Plimmerton and north of Upper Hutt being the most obvious examples. Two of these substations also supply two of the main water treatment plants providing potable water to the region at Te Marua and Wainuiomata treatment and pumping stations. Both plants have backup power supplies that can cover their emergency requirements but require network supply to operate at full capacity.

There are also locations where a single asset failure could spread and result in the total loss of one or more zone substations. This is partially mitigated through physical separation of the assets and laying of cables in separate conduits. By separating the buried assets, the potential causes of damage to multiple circuits are largely limited to external forces such as cable strikes or earthquakes.

11.4.2.3 Upstream Supply Failure

WELL takes supply from Transpower at Grid Exit Point (GXP) substations. There are nine GXPs in the Wellington region supplying WELL at either 33 kV or 11 kV, with some GXPs supplying at both voltages. While the loss of any of these substations will result in the loss of supply to one or more zone substations and a significant number of consumers, Central Park substation is the most significant. Central Park is a highly loaded substation and would have the largest impact in terms of both load lost and consumers without supply.

Central Park substation supplies seven zone substations with over 42,000 customer connections and a peak demand of approximately 190 MVA. There is very limited capacity for the shifting of load onto the Wilton GXP with approximately 17 MVA able to be transferred to Moore Street, Kaiwharawhara and Karori substations. The area supplied by Central Park contains the majority of the Wellington CBD and includes a number of high priority and regionally critical sites.

The Central Park site, shown in Figure 11-1, is constrained by the limited available space as well as the construction standards at the time of construction which increases the likelihood of a failure in one area spreading to adjacent areas or equipment. Large Transpower sites such as Penrose or Haywards are often 300-400m across while Central Park is barely over 50m with no fire separation between two of the transformers or between bus sections in the 33 kV switchroom.

Figure 11-1 Central Park Substation

This site supplies the majority of the CBD load in the national capital city and there is no alternate supply in the event of a failure of the site. The potential loss of the majority of Wellington city load is an unacceptable risk and there is ongoing work between WELL and Transpower looking at potential solutions to improve the resilience of the site. This is discussed further in Section 11.6.

11.4.2.4 Major Earthquake

The Wellington Region contains numerous known fault lines with the potential to cause a severe shaking event. The Wellington fault line runs through Thorndon, along the edge of the harbour and roughly follows State Highway 2 up the Hutt Valley. The proximity to urban centres and major transport links along with this being the most active of the major fault lines in the region means the Wellington Fault presents the highest risk to the region.

A report produced by WeLG in 2012 estimated the duration of three levels of service following an earthquake on the harbour section of the Wellington fault line. The levels of service were:

- **Emergency** – Hand held battery powered or local standby generators, during this stage damage assessment will begin and damaged equipment made safe;
- **Survival** – Limited supply to critical facilities, repair of equipment and restoration of service will begin with critical sites being prioritised; and
- **Operational** – Power reconnected for most customers with frequent outages for repair work, at this point businesses will be able to resume operation though possibly at a reduced capacity.

The WeLG report identified that most areas of the WELL network would remain at an Emergency level of service for 20-30 days requiring the restoration of road access to each area before a Survival state would be reached. An Operational level of service would be achieved 60-90 days following the restoration of road access. A major finding from this report was that road access would be a major factor in the extended outage durations expected following a major earthquake. In addition, telecommunications and water pumping are also dependent on roads for repair and electricity for operation.

The three most well studied fault lines in the region are the Wellington, Ohariu, and Wairarapa fault lines. These are shown in Figure 11-2, a map of the region created by GNS science.

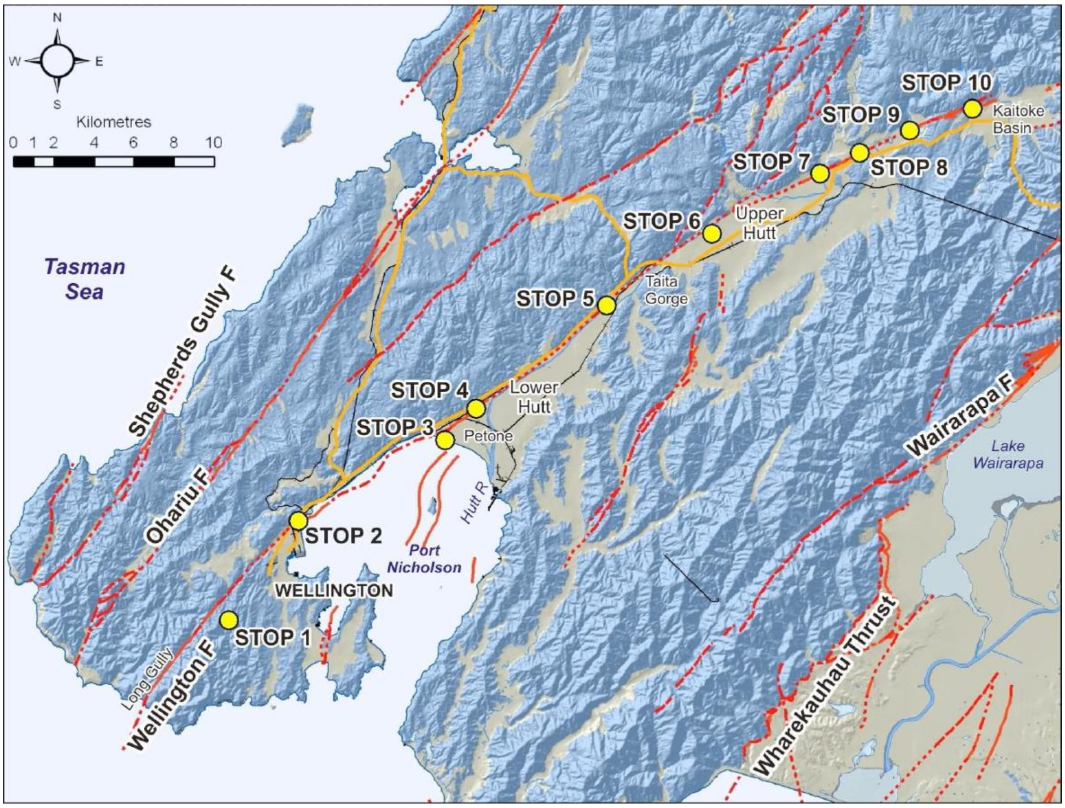


Figure 11-2 Wellington Region Fault Lines[66]

The Wellington fault line runs from Long Gully through Thorndon, along the edge of Wellington Harbour and roughly along State Highway 2 to Kaitoke. The Ohariu fault runs up the Ohariu valley, through Porirua and past Mana along the northern edge of the Pauatahanui inlet. The Wairarapa fault runs along the Rimutaka ranges and ruptured in 1855 resulting in an earthquake with a magnitude of 8.2, making it the most powerful earthquake recorded in New Zealand.

A rupture of any of these faults would lead to a severe earthquake in the region with a level of damage expected to be similar to or exceeding that of the February 2011 Christchurch earthquake. It is expected that large sections of the network will be without power immediately after a major event but that the majority of this will be able to be restored once equipment inspections and line patrols have been completed. After the initial restoration work, fault finding and repair work will have to be carried out on the remaining damaged areas of the network.

Following the 2016 Kaikoura Earthquake, there has been an increased awareness of the hazard posed by a major earthquake in the Wellington region, leading to the SCPP application discussed in Section 11.5.

11.5 WELL's Earthquake Readiness SCPP Delivery

11.5.1 Progress of the SCPP

In developing the SCPP application, an economically robust business case for investment in readiness initiatives to reduce the impact of an earthquake was created. These initiatives focus on readiness so that,

[66] Field Trip 1; Wellington Fault: Neotectonics and Earthquake Geology of the Wellington-Hutt Valley Segment. GNS Science (the stops on the picture refer to the stops made during the field trip).

in the event of a major earthquake, restoration efforts are not dependent on bringing equipment and materials from outside the region as significant damage to transport infrastructure is expected.

In March 2018, following the receipt of the Government Policy Statement in September 2017, the Commission approved WELL's SCPP. This enabled $31.24 million of additional spending targeted at improving the response following a major earthquake in the region. This SCPP was applied for and granted as a response to the November 2016 Kaikoura earthquake which highlighted the impact that a major earthquake centred within the region could have on the electricity network. The need identification stage of this showed that the key driver of restoration times would be the delays due to road access being cut off between network areas, as identified by the Opus report of 2013[67].

Road damage following a major earthquake could lead to the WELL network area being broken into five transport 'islands' with road access between areas not possible. These transport 'islands' and the predicted timeframes before transport links are opened are shown in Figure 11-3.

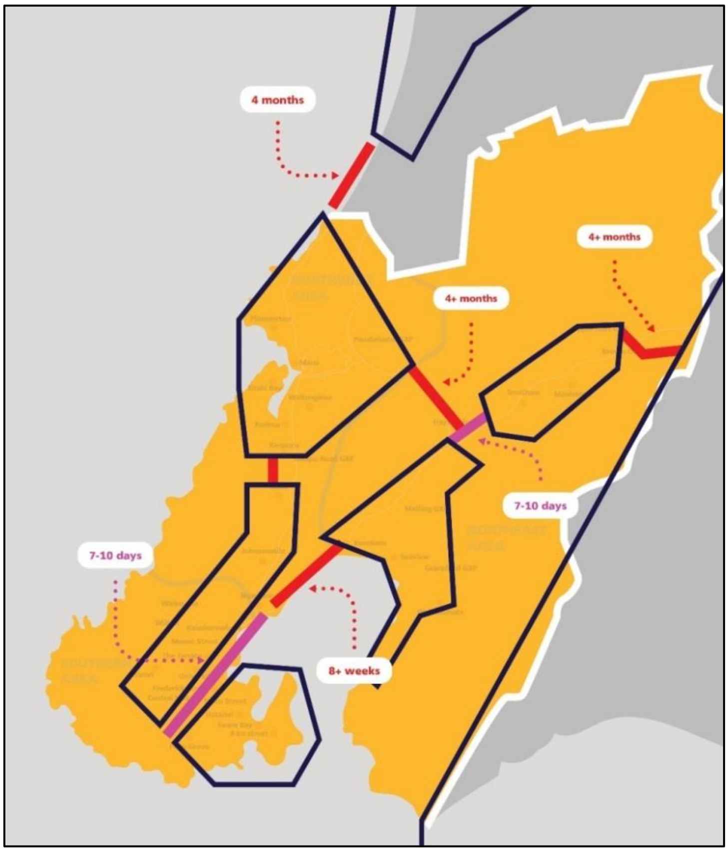


Figure 11-3 Affected Transport Links After a Major Earthquake

11.5.2 Delivery of SCPP Workstreams

Delivery of the WELL SCPP has been split into five workstreams with each of these being managed as a separate project:

1. Spares
2. Data Centres

[67] "Restoring Wellington's transport links after a major earthquake" Wellington Lifelines Group, March 2013.

3. Mobile Substations

4. Radio and Phones

5. Seismic Reinforcement

11.5.2.1 Spares

The spares workstream was split into three projects with overhead line spares, cable and joint spares, and the mobile switchboard. The spares workstream also included the setup of stores locations throughout the network.

The overhead and cable spares workstreams are now 100% complete. All underground and overhead spares have been purchased and are stored at sites throughout the region to enable repair of the 11 kV cable network to begin without waiting for transport routes to open. The mobile switchboard is nearing completion, and will be stored in Lower Hutt once it is delivered in 2020.

11.5.2.2 Data Centres

Three data centres are to be constructed and installed within the network to provide access to critical operating software and data in the event that communications to the Network Control Room are cut off.

Work is now almost complete on detailed design and elements of construction are underway. This workstream is projected to be completed by the end of 2020.

11.5.2.3 Mobile Substations

Two mobile substations are being constructed to restore supply where a substation is so damaged that both the transformers and switchboard are unable to be used. The detailed design stage is well progressed.

The substations are being constructed in a modular manner with the transformer and switchgear/controls units separately transportable. The transformer will be mounted on a trailer with the switchgear/control module fitting the dimensions of a standard 20ft shipping container. The decision to construct the substation in this manner, rather than on a single trailer as is more common, was due to transport considerations. With road access being potentially affected, a smaller trailer and container are more easily transported from the storage location to a damaged substation. With the modular arrangement only the required parts need to be transported and there is more flexibility in connection and the physical layout on site.

11.5.2.4 Radio and Phones

The radio workstream provides for an improved modern digital radio network, with more connectivity and improved coverage. An independent radio system will enable restoration work to commence without relying on public communications systems which could be damaged in an earthquake. The workstream is progressing well and will be completed in mid-2020.

The telephone workstream is complete and provides a Voice-over IP (VoIP) telephone network to improve communications functionality between the Network Control Rooms and all WELL zone substations. This improved telephone network has a robust configuration to ensure continued operation in a disaster scenario, when public communications networks may be compromised.

11.5.2.5 Seismic Reinforcement

Prior to the award of the SCPP, WELL had a programme of seismic reinforcement underway to improve buildings constructed before 1976, and that had been identified as earthquake prone, to above 33% of the current New Building Standard (NBS). Under the SCPP, this programme has been expanded to improving significant buildings (including zone substations and major switching stations) to 67% of NBS. This will reduce the risk of equipment damage or access issues affecting the restoration of the network following an earthquake.

A total of 91 buildings were identified for seismic strengthening under this expanded reinforcement programme. At the time of publication 74 buildings have been successfully strengthened. The strengthening programme will to run until the middle of 2020.

11.5.3 Expenditure Summary

A summary of the expenditure associated with the earthquake readiness SCPP is shown in Table 11-1, with the remaining expenditure shown in Table 11-2.

Risk Being Addressed	Proposed Initiatives	Capex	Opex	Total
33 kV cable faults	Emergency hardware	4,740	670	**5,410**
Loss of transformers and switchgear	Mobile substations and switchboard	4,730	-	**4,730**
11 kV cable and equipment faults	Critical emergency spares	4,940	-	**4,940**
Damage to equipment in buildings	Seismic reinforcement of critical substations	10,400	-	**10,400**
Loss of data and communication links	Additional data centres and improved communication systems	5,260	500	**5,760**
TOTAL		**30,070**	**1,170**	**31,240**

Table 11-1 Summary of Proposed Initiatives (\$K in constant prices)

11.5.3.1 SCPP Expenditure Forecast

Asset Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	4,380	-	-	-	-	-	-	-	-	-
Distribution Poles and Lines	-	-	-	-	-	-	-	-	-	-
Distribution Cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations	-	-	-	-	-	-	-	-	-	-
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets	-	-	-	-	-	-	-	-	-	-
Total (Network)	**4,380**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Non-Network Assets	3,450[68]	-	-	-	-	-	-	-	-	-
Total	**7,830**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 11-2 SCPP Expenditure Forecast
($K in constant prices)

11.6 Wellington Lifelines Regional Resilience Project

The Wellington Lifelines Regional Resilience Project was initiated by WeLG in the aftermath of the 2016 Kaikoura Earthquake, to assess the resilience of lifeline services and to compile a coordinated business case for resilience expenditure. The project published its report in October 2019, which can be found at https://wremo.nz/about-us/lifeline-utilities/.

The economic modelling indicated that a single 7.5 magnitude event on the Wellington fault line could adversely impact the national GDP by $16.7 billion on over a five year period. Hazard and damage state modelling was done through RiskScape, a multi-hazard risk assessment tool developed by GNS and NIWA. Lifeline industries were engaged to assist with fragility curves and damage restoration time frames. Economic impact was assessed using MERIT (Modelling the Economics of Resilient Infrastructure Tool) which assesses not only the immediate damage but longer term economic impacts as well.

A range of options of varying expenditure were identified and passed through the same modelling process to identify the overall benefit, recommending an investment of $3.9 billion which could reduce the GDP impact of a major earthquake by $6.16 billion.

The preferred option included a $205 million investment in the regional electricity infrastructure, as shown in Figure 11-4.

[68] The expenditure is included in the Non-network forecast in Section 12 and is shown here for completeness

Lifeline Infrastructure	Preferred Investment Programme		
	Initiative Name	Owner	Indicative Cost
Electricity	Central Park Substation improved resilience	Transpower, WE*	$40M
	Seismic upgrade of cables and creation of 33kV Rings	WE*	$160M
	Central Park to Frederick St cables replacement	WE*	$5M

Figure 11-4 Electricity Expenditure for Preferred Regional Resilience Investment Option
Source: Wellington Lifelines Project Report, 2019

The preferred option involves three initiatives to improve the resilience of the electrical networks in the Wellington region. The most vulnerable assets in the region are the fluid and gas-filled subtransmission cables, which could be mitigated by cable replacement in a more resilient ring configuration. Another major risk is the single point of failure at Central Park Substation, with this substation being the main supply point for most of Wellington City. The third initiative is the replacement of the Central Park to Frederick Street cable, which was separated from the main seismic upgrade of cables because the cable is currently being replaced for loading reasons.

These resilience initiatives were not included within the SCPP application as this was focussed on readiness initiatives and not resilience. As such these works were outside the scope of the SCPP and the level of investment required is beyond what can be funded within the DPP allowances. While the items planned as part of the SCPP programme will provide an improvement to restoration times, there may still be significant outages in many areas of the network depending on the scale of any earthquake occurring, hence the potential need for this extra work.

11.6.1 Central Park

There is a significant risk posed by a potential loss of supply at Central Park GXP. A longlisting exercise has been completed with Transpower and the initial analysis of options generated through this showed that the most effective means of reducing this risk would be the construction of a smaller “Central Park 2” substation which will replicate a portion of the existing site at a nearby location. The Central Park 2 substation construction would coincide with the decommissioning of one transformer bank at the current site. This transformer would be replaced with a transformer at the new site. The new site would also contain a 33 kV bus section with one supply to each of the connected WELL zone substations. This substation would be operated as an extension of the existing GXP, although physically separated. The work would be funded under a new customer connection contract with Transpower and would be recovered as a pass through cost to end consumers. The Transpower-led solution requires consultation with wider stakeholders in the 2020/21 year, followed by detailed design. Transpower’s plan is to start construction in 2023 for completion in Q1 2025.

This option is more cost effective than the construction of a full size GXP and will effectively mitigate the risk presented by this single point of failure.

Other options looked at involved the construction of new GXPs or zone substations supplied from Wilton or through a new undersea cable crossing the harbour. These options were significantly more costly than the preferred Central Park 2 substation option.

11.6.2 Subtransmission Fluid Filled Cables

The majority of the subtransmission cable in the WELL network is fluid pressurised cable, installed between 1960 and 1980. Fluid filled cables are particularly prone to damage in an earthquake as well as being expensive and time consuming to repair, requiring skills that are not readily available within the region.

The condition of these cables is individually monitored and assessed against asset health and criticality criteria. These cables have historically given a high level of reliability and are manageable from an operational point of view for the planning period as described in Section 7.5.1.

A significant earthquake could result in cable damage that does not immediately cause a fault, such as fluid leaks or sheath damage, but which would have a negative impact on the reliability of the network. Repairing a fluid leak is a difficult task as the means of locating the leak can take time when there is no associated cable fault, resulting in leaks having a high cost to locate and repair, as well as ongoing costs while fluid is being lost. Once the damage is located, repair work can also be time consuming and requires a specialised skill set to be brought in from outside the region. Due to these repair difficulties and the high likelihood of a fault causing damage in an earthquake, repair of these cables may not be a viable solution. The SCPP spares project provides equipment for the construction of temporary overhead lines in the worst affected areas following an earthquake.

Modern cables installed within ducts are less likely to sustain this type of damage and do not have the labour resourcing issues associated with fluid filled cables. Resilience can also be improved by diversifying the cable routes to substations and providing greater interconnection between Transpower GXPs. Diversified cable routes will mean that localised cable damage is less likely to cause an outage at any site compared with the current network layout where both circuits to a substation are typically run alongside each other.

The WeLG RRP PBC analysed the effect of subtransmission upgrades on the potential restoration times, based on damage modelling work carried out by GNS Science. The construction of rings was grouped into three separate projects for the purpose of this analysis, a subtransmission ring through the eastern suburbs of Wellington, a subtransmission ring in Lower Hutt, and the seismic upgrade of other fluid filled cables. The damage modelling has identified the construction of two subtransmission rings as the preferred option for improving the resilience of electricity distribution in the Wellington region.

Under business as usual, some of this work is likely to be completed as 33 kV circuits are replaced due to condition or capacity, although this is likely to happen over a 40-50 year timeframe. The regional resilience project is looking at the potential resilience benefits of accelerating this programme.

Subtransmission rings would allow for greater load transfer between zone substation and GXPs and the associated cable replacement would enable diversification of cable routes. The predicted earthquake performance along proposed cable routes would be considered when selecting the route for any new cables.

Section 12
Customer Initiated Projects and Relocation

12 Customer Initiated Projects and Relocations

This section provides information on customer initiated projects and relocations on WELL's network over the next 10 years. New connections or the changing of existing connections initiated by customer projects have an impact on WELL's long term network planning and development strategy. The introduction of modern technologies (e.g. energy storage system, demand response programmes etc) will also affect WELL's ability to maintain supply quality and network capacity.

The budgeted expenditure for 2020 is $13.9 million. Expenditure for customer initiated projects and relocations have been aggregated in the budget in accordance with the categories discussed below.

12.1 New Connection Application Process

Individual customers wanting a new connection requiring a network extension, e.g. a new point of supply on their boundary via a pit or pillar, submit a Service Request (SR), which to date has been captured through the Telnet system. This system is being phased out with new connection applications being made through WELL's website, allowing customers to register their request for a design/quote (https://www.welectricity.co.nz/getting-connected/new-online-forms-holder/get-connected/). SRs are broadly categorised into either residential or business connections, and into fuse sizing requirements of 60A, 100A or greater than 100A rating requests. The SRs are assessed by the Service Delivery team and allocated directly to a contractor if it is a simple connection, or remain with the team for more complex requests.

These simple SRs are typically residential customer connections which are allocated to contractors for pricing and construction. Where SRs are identified as complex, the Service Delivery team evaluate the customer's requirements, collect salient information for these applications, construct a brief project scope with material requirements, and compile a Technical Approval (TA) form for submission to the Asset Management team who determine network policy criteria and connection approval.

Upon receipt of this TA request, the Engineering Planning team reviews and further defines the project as either minor or major, and completes the approval process accordingly. For complex–minor projects, basic checks include system capacity analysis, contingency analysis, equipment type review, and secondary asset review. After completing assessments, the TA is returned to Service Delivery for tendering. Once the competitive tender process is complete, a tender evaluation is undertaken which will determine pricing to enable a quotation. This is then structured into a formal offer and presented to the customer.

Applications classified as complex–major require more in-depth analysis. Applications such as these may trigger a High Level Response (HLR) query. A study is conducted illustrating the load flow analysis and network constraints. Several viable options for delivering the required supply capacity are detailed inclusive of project durations and cost estimates. This HLR is then presented to the customer to enable them to select an option that best matches their requirements.

If the customer is interested in pursuing a specific option, a Detailed Solution Development (DSD) study is initiated to further refine the project requirements and estimates. This is completed by an independent consultant. One of the primary objectives of this exercise is to validate the selected option and refine the estimate.

Upon completion of the DSD process the customer may opt to pursue the selected option. Where the level of complexity of the planned installation is high, the Engineering Planning team will compile a brief design scope of works for Service Delivery to tender to independent design consultants for a detailed design. The detailed design is integral for the construction tender process to enable pricing from the installation contractors. On completion of the tender evaluation and internal approval processes, Service Delivery will begin to make a formal connection offer to the customer based on the requirements specified in the development process.

12.2 New Connections and ICPs

For several years the number of new dwellings consented annually in the Wellington region across the four local authorities has been increasing, driven by the growth in apartments within the Wellington CBD and subdivision growth along the northern belt. Figure 12-1 shows the number of new dwellings consented for apartments, retirement village units, townhouses, flats and units over the last six years.

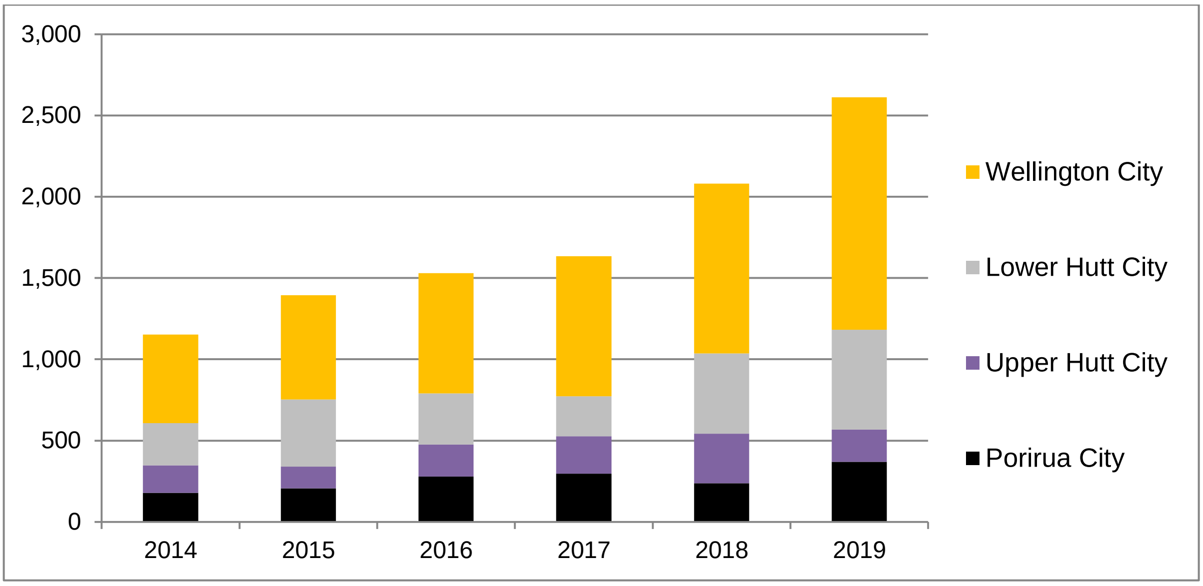


Figure 12-1 Number of New Dwellings Consented in the Wellington Region

Figure 12-2 shows the number of new connections added to the Wellington network since 2015[69] and the expected new connections for the next five years. This shows that the number of new connections has increased. The number of new ICP connections does not align exactly to building consents due to the lag between consent approval and connecting to the network (which can be between one and five years) and because multiple apartments with a building consent each can be serviced by a single ICP connection.

[69] The 2020 year includes an estimate for March 2020 as this was not finalised in time to include in the AMP.

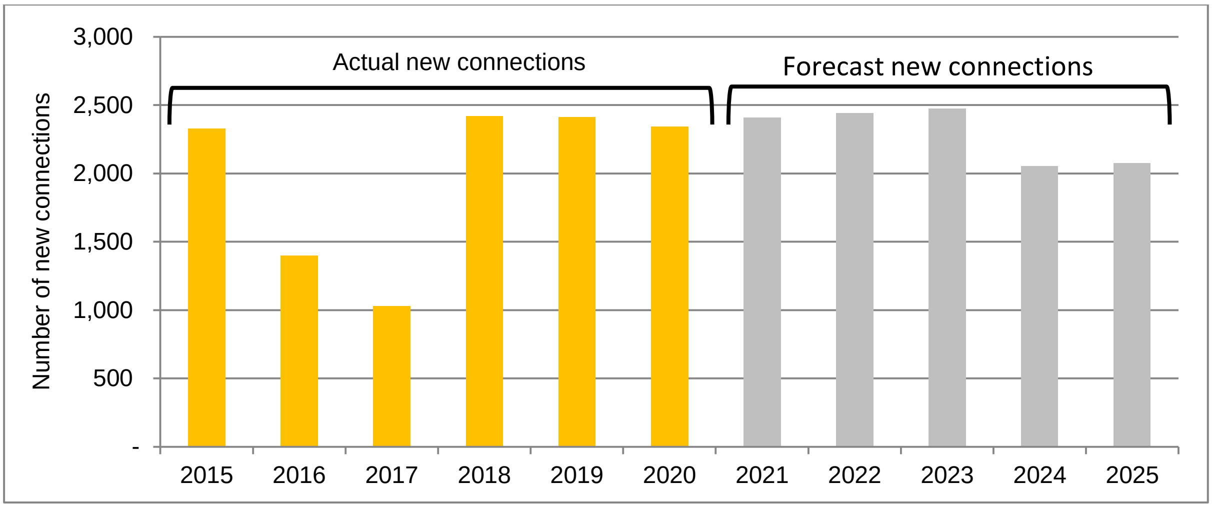


Figure 12-2 New Connections in the Wellington Region

WELL expects the current levels of new connections to continue for another three years. This is based on building consents and WELL's forward work programme indicating that the current high growth of new buildings is expected to continue for the next few years. The volume of new connections is expected to decline in the medium term as the number of new connections returns back in line with Wellington's population growth as housing construction catches up with demand.

12.3 Substations

These projects include new substations and HV connections, often for the increased capacity requirements of new businesses in either new or repurposed industrial sites. The requests for large substation connections have been consistent for several years. The forecast is set conservatively to reflect the uncertainty about whether individual projects will go ahead, however a number of large customer projects requiring additional capacity in Wellington and Porirua districts are proposed which could significantly increase expenditure if the customers decide to proceed in 2020.

12.4 Subdivisions

Small and infill subdivisions remain at similar levels to previous years. Developers continue a trend seen in 2016 where appetite for large scale residential (>100 lots) subdivisions is still increasing, particularly 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.

12.5 Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included within the customer substation area of the customer connection forecasts.

12.6 Relocations

Primarily these projects are initiated by NZTA or local authorities, but can also be private customer initiated relocations. Transmission Gully and local authority road safety improvements are critical projects in this category.

12.7 Consumer Connections Summary for 2020-2030

The total forecast consumer connection capital expenditure for 2020 to 2030 is presented in Table 12-1.

Consumer Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Substation	3,509	2,509	2,509	2,502	2,502	2,502	2,502	2,502	2,502	2,502
Subdivision	4,421	4,421	4,421	4,409	4,409	4,409	4,409	4,409	4,409	4,409
High Voltage Connection	83	83	83	83	83	83	83	83	83	83
Residential Consumers	2,915	2,915	2,915	2,907	2,907	2,907	2,907	2,907	2,907	2,907
Public Lighting	142	142	142	142	142	142	142	142	142	142
Total	**11,070**	**10,070**	**10,070**	**10,041**	**10,041**	**10,041**	**10,041**	**10,041**	**10,041**	**10,041**

Table 12-1 Consumer Connection Capital Expenditure Forecast ($K in constant prices)

12.8 Asset Relocations Summary for 2020-2030

The forecast asset relocation capital expenditure, which is primarily related to either roading projects or the undergrounding of existing overhead network for subdivision development, is presented in Table 12-2.

Programme	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Asset Relocations	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029	2,049
Total	**1,783**	**1,801**	**1,819**	**1,837**	**1,874**	**1,912**	**1,950**	**1,989**	**2,029**	**2,049**

Table 12-2 Asset Relocation Capital Expenditure Forecast ($K in constant prices)

Section 13

Expenditure Summary

13 Expenditure Summary

This section provides an overview of WELL's forecast capital and operational expenditure over the planning period in order to implement this AMP.

13.1 Capital Expenditure 2020-2030

13.1.1 Consumer Connections

The total forecast consumer connection capital expenditure for 2020 to 2030, as discussed in Section 12.1.7, is presented in Table 13-1.

Consumer Type	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Substation	3,509	2,509	2,509	2,502	2,502	2,502	2,502	2,502	2,502	2,502
Subdivision	4,421	4,421	4,421	4,409	4,409	4,409	4,409	4,409	4,409	4,409
High Voltage Connection	83	83	83	83	83	83	83	83	83	83
Residential Customers	2,915	2,915	2,915	2,907	2,907	2,907	2,907	2,907	2,907	2,907
Public Lighting	142	142	142	142	142	142	142	142	142	142
Total	**11,070**	**10,070**	**10,070**	**10,041**	**10,041**	**10,041**	**10,041**	**10,041**	**10,041**	**10,041**

Table 13-1 Consumer Connection Capital Expenditure Forecast ($K in constant prices)

13.1.2 System Growth

The total forecast capital expenditure for system growth and security of supply for 2020 to 2030, is presented in Table 13-2. In addition to system growth expenditure discussed in Section 8, this includes network capital expenditure on the emerging technology related development plan as discussed in Section 9.

Asset Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Subtransmission	1,200	3,100	3,400	-	600	2,560	4,000	6,000	4,000	5,000
Zone Substations	500	1,700	3,500	3,800	5,450	8,500	3,400	2,000	6,000	7,000
Distribution Poles and Lines	-	-	-	-	-	-	-	-	-	-
Distribution Cables	320	1,200	2,000	2,900	500	500	3,800	1,100	500	500
Distribution Substations	500	10	10	10	10	500	500	500	500	500
Distribution Switchgear	260	40	20	600	-	-	-	-	-	-
Other Network Assets[70]	970	2,530	1,765	1,660	1,320	2,795	3,345	3,495	3,495	3,855
Total	**3,750**	**8,580**	**10,695**	**8,970**	**7,880**	**14,855**	**15,045**	**13,095**	**14,495**	**16,855**

Table 13-2 System Growth Capital Expenditure Forecast
($K in constant prices)

13.1.3 Asset Replacement and Renewal

The total forecast capital expenditure for asset replacement and renewal for 2020 to 2030 as discussed in Section 7 is presented in Table 13-3. This includes provision for replacements that arise from condition assessment programmes during the year.

Asset Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Subtransmission	412	-	-	500	3,000	-	-	2,000	2,000	-
Zone Substations	550	1,450	2,400	200	200	200	200	200	200	200
Distribution Poles and Lines	7,452	7,185	7,437	7,265	7,006	6,924	7,007	6,865	6,494	6,446
Distribution Cables	761	870	875	881	889	1,895	1,902	3,409	3,416	3,423
Distribution Substations	5,332	3,797	3,731	4,065	4,336	4,825	4,825	4,825	4,825	4,825
Distribution Switchgear	4,714	4,256	4,413	4,373	5,208	5,346	5,350	5,359	5,355	5,352
Other Network Assets	2,579	2,063	2,742	2,884	2,987	2,831	2,821	2,727	2,655	2,477
Total	**21,800**	**19,621**	**21,598**	**20,168**	**23,626**	**22,021**	**22,105**	**25,385**	**24,945**	**22,723**

Table 13-3 System Asset Replacement and Renewal Capital Expenditure Forecast
($K in constant prices)

[70] Other Network Assets includes the capital expenditure required for emerging technologies.

13.1.4 Asset Relocations

The forecast asset relocation capital expenditure, primarily related to roading projects, is presented in Table 13-4.

Programme	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Roading Relocations	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029	2,049
Total	**1,783**	**1,801**	**1,819**	**1,837**	**1,874**	**1,912**	**1,950**	**1,989**	**2,029**	**2,049**

Table 13-4 Asset Relocation Capital Expenditure Forecast
($K in constant prices)

13.1.5 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 Table 13-5.

Programme	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Worst Performing Feeders	2,455	1,842	2,017	2,013	2,013	2,155	2,199	2,244	2,290	2,400
Extreme Event Mitigation	-	250	-	-	-	-	-	-	-	-
Total Quality of Supply	**2,455**	**2,092**	**2,017**	**2,013**	**2,013**	**2,155**	**2,199**	**2,244**	**2,290**	**2,400**
Seismic Programme (BAU)	1,167	700	300	650	-	-	-	-	-	-
Streamlined CPP	4,380	-	-	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	**5,547**	**700**	**300**	**650**	**-**	**-**	**-**	**-**	**-**	**-**

Table 13-5 Reliability, Safety and Environmental Capital Expenditure
($K in constant prices)

13.1.6 Non-network Assets

The forecast capital expenditure for non-network assets is presented in Table 13-6.

Routine Expenditure	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Software and Licenses	650	1,214	1,219	1,025	911	1,286	1,499	1,130	1,173	795
IT Infrastructure	570	521	551	455	449	634	738	557	578	392
Capitalised Leases	-	-	-	-	790	-	-	-	-	-
Streamlined CPP	3,450	-	-	-	-	-	-	-	-	-
Total Non-network Assets	**4,670**	**1,735**	**1,770**	**1,480**	**2,150**	**1,920**	**2,237**	**1,687**	**1,750**	**1,187**

Table 13-6 Non-Network Asset Capital Expenditure Forecast
($K in constant prices)

13.1.7 Capital Expenditure Summary

The total combined capital expenditure on assets is presented in Table 13-7.

Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Consumer Connection	11,070	10,070	10,070	10,041	10,041	10,041	10,041	10,041	10,041	10,041
System Growth	3,750	8,580	10,695	8,970	7,880	14,855	15,045	13,095	14,495	16,855
Asset Replacement & Renewal	21,800	19,621	21,598	20,168	23,626	22,021	22,105	25,385	24,945	22,723
Asset Relocations	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029	2,049
Reliability, Safety & Environment (other)	5,547	700	300	650	-	-	-	-	-	-
Quality of Supply	2,455	2,092	2,017	2,013	2,013	2,155	2,199	2,244	2,290	2,400
Subtotal - Capital Expenditure on Network Assets	**46,405**	**42,864**	**46,499**	**43,679**	**45,434**	**50,984**	**51,340**	**52,754**	**53,800**	**54,068**
Non-Network Assets	4,670	1,735	1,770	1,480	2,150	1,920	2,237	1,687	1,750	1,187
Total – Capital Expenditure on Assets	**51,075**	**44,599**	**48,269**	**45,159**	**47,584**	**52,904**	**53,577**	**54,441**	**55,550**	**55,255**

Table 13-7 Capital Expenditure Forecast
($K in constant prices)

13.2 Operational Expenditure 2020-2030

The total forecast operational expenditure for 2020 to 2030 is shown in Table 13-8.

Category	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Service interruptions & emergencies maintenance	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478
Vegetation management	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801
Routine & corrective maintenance and inspection	9,016	9,216	9,216	9,216	9,216	9,216	9,216	9,216	9,216	9,216
Asset replacement & renewal maintenance	958	958	958	958	958	958	958	958	958	958
Subtotal –Operational Expenditure on Network Assets	**16,254**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**	**16,454**
Non-network Operational Expenditure	18,590	18,590	18,590	18,590	18,590	18,590	18,590	18,590	18,590	18,590
Total – Operational Expenditure	**34,843**	**35,043**	**35,043**	**35,043**	**35,043**	**35,043**	**35,043**	**35,043**	**35,043**	**35,043**

Table 13-8 Operational Expenditure Forecast (\$K in constant prices)

Appendices

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.	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 change in response to legislative changes.	The current regulatory environment does not allow for resilience spend, and this position is assumed to continue for the duration of the plan	Correspondence from the Commission indicates that they will not consider a single-issue CPP for Resilience.
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 though building consents do show an increase. 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.
Operational Expenditure - Routine Inspection and Maintenance	Any material change to the annual maintenance programme or costs associated with them may lead to an increase, or decrease in the Opex costs associated with inspection and maintenance.	The inspection and maintenance expenditure proposed will broadly remain within forecast levels for the next four years.	The inspection programme is defined by comprehensive maintenance standards covering all asset classes. Managing mature network assets, the routine of inspection and servicing is not likely to change significantly.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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 year. Aging assets may lead to higher levels of reactive maintenance required longer term and a change of the FSA may result in changes to the associated reactive maintenance expenditure.	Reactive maintenance rates defined in FSA, which are expected to be maintained at similar levels.
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 of 2.0% pa across the planning period.	The rates used 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 2020-2025 were set by the Commission's 2019 DPP Determination. It is assumed that the targets will remain constant for 2025-2030.	The targets adopted in this plan align with the Commission's 2014 determination until 2021 and the 2019 determination for 2021-2030. This reflects WELL's intention to maintain network reliability at current levels.
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.	The expected impact of the 2019 DPP reset has been assessed, providing stability through to 2025.
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 WELL during the planning period, other than those identified in Section 8 and the Section 11.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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.
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 WELL is likely to be modest for the foreseeable future.	Assumptions of regional GDP growth are supported by observations of demand on the network and local business activities.
Business cycle	The evolution of a business and its operating environment can impact on strategic decision making and overall approach.	The business cycle is expected to change due to the introduction of new technologies and appropriate investment forecasts have been included into this plan.	The changes to consumer behaviour due to the penetration of new technologies have been based on the worldwide trend of lower costs associated with such technologies making them more accessible.
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 changes that will result in a rapid uptake of new technology by consumers which could result in higher expenditure on network reinforcement. This reinforcement will be deferred by enabling new technologies on the network and by moving towards becoming a Distribution System Operator.	At demand side, displacement or disruptive technologies such as electric vehicles, vehicle-to-grid and distributed generation will begin to gain penetration into Wellington. Trends in the area of disruptive technology are being closely monitored and plans forecast to prepare for these changes are in Section 9.
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 2019 Plan

During the past year, WELL has continued the review of its asset management strategy and practices. Progress against the gaps identified in the 2019 AMP, along with material changes to network development and lifecycle asset management plans, is shown in the Table B-1.

2019 AMP Section	Item	Description
3.4.2.2	Takapu Road to Ngauranga 33 kV Circuit	Transpower has recently informed WELL that they intend to decommission the circuit from Takapu Road to Ngauranga Zone Substation, which is a 110 kV circuit being operated at 33 kV.
		Update: Detailed solution study underway between WELL and Transpower to investigate options.
3.6.1.1	Customer Service	WELL is establishing new services on the existing website to make the process of applying for a new connection easier to understand.
		Update: A new web portal is in place for logging connection requests.
3.7.1.4	Use of Network Agreement	Revise Use of Network Agreement in consideration of the Authority's proposed Default Distributor Agreement and commence negotiations with retailers using the network.
		Update: WELL is working with the Authority and other market participants on an industry default Use of System Agreement. WELL will work with retailers to decide whether to move to the new agreement or to remain on the current agreements.
7.5.1	Evans Bay 1 gas leak	A maintenance task has been created for the location, identification and repair of the gas leak on this cable.
		Update: Work has been undertaken to locate the increased gas leak, however it has been determined that it is not economic to continue with a repair. The cable will be de-energised upon completion of the Evans Bay 33 kV bus in 2022.
7.5.1	Korokoro A subtransmission sheath faults	Sheath fault repairs on Korokoro A were deferred to 2020 due to the Evans Bay gas leak.
		Update: Sheath fault testing was completed in early 2020, and a plan is under development for fault location and repair.
7.5.2.1	Evans Bay Transformer	Detailed designs are expected to begin in 2019.

2019 AMP Section	Item	Description
	Replacement	**Update:** Designs for the site
7.5.2.1	Mana Transformer Replacement	Allowance for this replacement has been made in 2022/23 of this AMP.
		Not Required: The Mana transformer has been fitted with online monitoring equipment, which has provided an updated end of life estimate outside the horizon of the 2020 AMP.
7.5.2.2	Reyrolle Type C circuit breakers	Replacement of the Reyrolle Type C circuit breakers at Gracefield is underway and due for completion by the end of 2019.
		Complete: The Type C circuit breakers at Gracefield were replaced in 2019.
7.5.9.3	Load Control Equipment	Renewal and Refurbishment
		Update: Business case for the replacement of the Foxboro master station will be presented in 2020. The Secondary NDRP details a replacement programme for the load control PLC's starting in 2020.
8	System Growth Capital Expenditure Forecast	A new process provided a more conservative to managing the risk of system security. Considering the potential impact from emerging technology. This has resulted in a re-evaluation of expected System Growth capital expenditure.
8.1.8	Non-Network Solution Policy	Continue with the development of a future pricing roadmap to keep the network efficient and enable the introduction of new technology with minimal network impact.
		Update: WELL is introducing residential time of use pricing in 2020, which will incentivise customers shifting load out of peak periods.
8.1.9.1	Connections Policy	The new AS/NZS 4777 standard is expected to be accepted into the regulations in 2020, following which WELL will update its standards. This update will use the EEA "Guideline for the Connection of Small-Scale Inverter Based Distributed Generation" as a template.
		Update: Public consultation published by the Authority in December 2019. The Authority Board decision is expected in April 2020. WELL will update its standards after this happens.

2019 AMP Section	Item	Description
10.1.1.1	SCADA	Investigating the introduction of new software to replace the TrendSCADA data historian tool.
		Ongoing: This is expected to be implemented as part of the SCADA system upgrade.
11.4.1	Seismic Reinforcement of Equipment and Buildings	Ongoing assessment of nominated substation buildings in accordance with the seismic assessment programme.
		In Progress: All pre-1976 buildings have been assessed. A work programme is in place to strengthen buildings identified as being earthquake prone by the end of 2023. There are now 17 buildings left to be addressed on this programme.
11.4.2.4	Central Park GXP	Long term plan to address single point of failure risks at Central Park.
		Update: Work ongoing with Transpower to improve fire detection at Central Park. Transpower has commenced Central Park 2 detailed solution development.
11.5	33kV Overhead Emergency Corridors	Completion of designs for the remaining overhead sub-transmission routes and procurement of components to allow construction of 19 km of line.
		Complete: All line corridor designs complete, and all components purchased and distributed in storage sites around the region. Process to routinely review designs to ensure continued adequacy to be implemented in 2020.

Table B-1 Progress against Actions Identified in 2019 AMP

Comparisons between forecast expenditure from the 2019 AMP and the actual expenditure for the 2019/20 regulatory year are shown below in Table B-2 for operational expenditure and Table B-3 for capital expenditure.

Expenditure Category	2019/20 Forecast from 2019 AMP	2019/20 Actuals	Variation
Service Interruptions and Emergencies	3,913	4,771	858
Vegetation Management	1,851	1,584	(267)
Routine and Corrective Maintenance and Inspection	10,147	8,116	(2,031)
Asset Replacement and Renewal	834	958	124
System Operations and Network Support	5,884	6,460	576
Business Support	11,982	10,667	(1,315)
Operational expenditure	**34,611**	**32,556**	**(2,055)**

Table B-2 Comparison of Operational Expenditure against 2019 AMP Forecasts ($K, forecast in nominal dollars)

Operating expenditure was approximately 4% lower than forecast, with variances due to programme timing with the previous regulatory year, and accounting rule changes regarding capitalisation of leases that were previously opex.

Expenditure Category	2019/20 Forecast from 2019 AMP	2019/20 Actuals	Variation
Consumer Connection	8,189	13,886	5,697
System Growth	6,309	1,748	(4,561)
Asset Replacement and Renewal	19,595	21,816	2,221
Asset Relocations	2,499	2,396	(103)
Reliability, Safety and Environment	17,802	13,568	(4,234)
Expenditure on Non-network Assets	4,989	2,330	(2,659)
Capital Expenditure	**59,382**	**55,744**	**(3,638)**

Table B-3 Comparison of Capital Expenditure against 2019 AMP Forecasts ($K, forecast in nominal dollars)

Significant variations between forecast capital expenditure and actual expenditure were as follows:

- A variation of $5.7 million in Consumer Connection expenditure due to a general uplift in development activity across the region and several large one-off customer projects;
- A variation of $4.6 million in System Growth expenditure due to a deferral of expenditure for the Frederick Street subtransmission cable project so that further feasibility studies (particularly ground penetrating radar surveys) could be undertaken along the entire cable route;
- A variation of $2.2 million in Asset Replacement and Renewal due to higher than forecast capitalised fault repairs and capitalisation of operating leases;

- A variation of $4.2 million in Reliability, Safety and Environmental expenditure which was driven by a delay in the SCPP mobile substation programme which will now be completed in the 2020/21 regulatory year (still within the SCPP project timeframe); and
- A variation of $2.7 million in Non-Network Assets due to a delay in the SCPP data room earthquake readiness project. The data room project will now be completed in the 2020/21 regulatory year (still within the SCPP project timeframe).

Appendix C Schedules

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2020 – 31 March 2030**

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												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	13,886	11,291	10,476	10,686	10,869	11,087	11,308	11,534	11,765	12,000	12,240
11	System growth	1,748	3,825	8,927	11,350	9,709	8,700	16,729	17,282	15,343	17,323	20,546
12	Asset replacement and renewal	21,816	22,236	20,414	22,920	21,830	26,085	24,799	25,392	29,743	29,812	27,699
13	Asset relocations	2,396	1,819	1,874	1,930	1,988	2,069	2,153	2,240	2,330	2,425	2,498
14	Reliability, safety and environment:											
15	Quality of supply	1,949	2,504	2,177	2,140	2,179	2,223	2,427	2,526	2,629	2,737	2,926
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	11,619	5,658	728	318	704	-	-	-	-	-	-
18	**Total reliability, safety and environment**	13,568	8,162	2,905	2,459	2,883	2,223	2,427	2,526	2,629	2,737	2,926
19	**Expenditure on network assets**	53,413	47,333	44,595	49,345	47,280	50,163	57,417	58,974	61,810	64,296	65,909
20	Expenditure on non-network assets	2,330	4,763	1,805	1,878	1,602	2,373	2,162	2,570	1,977	2,091	1,447
21	**Expenditure on assets**	55,744	52,096	46,400	51,223	48,882	52,537	59,579	61,544	63,787	66,388	67,356
22												
23	*plus* Cost of financing	175	178	176	173	199	220	225	227	229	234	238
24	*less* Value of capital contributions	9,134	10,584	9,827	9,217	9,345	9,556	9,773	9,995	10,222	10,455	10,679
25	*plus* Value of vested assets											
26								-	-			
27	**Capital expenditure forecast**	46,785	41,690	36,749	42,179	39,736	43,200	50,030	51,776	53,794	56,166	56,915
28												
29	Assets commissioned	46,785	41,690	36,749	42,179	39,736	43,200	50,030	51,776	53,794	56,166	56,915
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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
32		**$000 (in constant prices)**										
33	Consumer connection	13,886	11,070	10,070	10,070	10,041	10,041	10,041	10,041	10,041	10,041	10,041
34	System growth	1,748	3,750	8,580	10,695	8,970	7,880	14,855	15,045	13,095	14,495	16,855
35	Asset replacement and renewal	21,816	21,800	19,621	21,598	20,168	23,626	22,021	22,105	25,385	24,945	22,723
36	Asset relocations	2,396	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029	2,049
37	Reliability, safety and environment:											
38	Quality of supply	1,949	2,455	2,092	2,017	2,013	2,013	2,155	2,199	2,244	2,290	2,400
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	
40	Other reliability, safety and environment	11,619	5,547	700	300	650	-	-	-	-	-	-
41	**Total reliability, safety and environment**	13,568	8,002	2,792	2,317	2,663	2,013	2,155	2,199	2,244	2,290	2,400
42	**Expenditure on network assets**	53,413	46,405	42,864	46,499	43,679	45,434	50,984	51,340	52,754	53,800	54,068
43	Expenditure on non-network assets	2,330	4,670	1,735	1,770	1,480	2,150	1,920	2,237	1,687	1,750	1,187
44	**Expenditure on assets**	55,744	51,075	44,599	48,269	45,159	47,584	52,904	53,577	54,441	55,550	55,255
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											

	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 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	221	407	616	828	1,045	1,267	1,493	1,724	1,959	2,199
System growth	-	75	347	655	739	820	1,874	2,237	2,248	2,828	3,691
Asset replacement and renewal	-	436	793	1,322	1,662	2,459	2,778	3,287	4,358	4,867	4,976
Asset relocations	-	36	73	111	151	195	241	290	341	396	449
Reliability, safety and environment:											
Quality of supply	-	49	85	123	166	210	272	327	385	447	526
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	111	28	18	54	-	-	-	-	-	-
Total reliability, safety and environment	-	160	113	142	220	210	272	327	385	447	526
Expenditure on network assets	-	928	1,732	2,846	3,601	4,729	6,432	7,634	9,056	10,496	11,841
Expenditure on non-network assets	-	93	70	108	122	224	242	333	290	341	260
Expenditure on assets	-	1,021	1,802	2,954	3,723	4,953	6,675	7,966	9,345	10,837	12,101

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Consumer types defined by EDB**	$000 (in constant prices)					
Substation	3,459	3,509	2,509	2,509	2,502	2,502
Subdivision	6,095	4,421	4,421	4,421	4,409	4,409
High Voltage Connection	114	83	83	83	83	83
Residential Consumers	4,019	2,915	2,915	2,915	2,907	2,907
Public Lighting	198	142	142	142	142	142
**include additional rows if needed*						
Consumer connection expenditure	13,886	11,070	10,070	10,070	10,041	10,041
less Capital contributions funding consumer connection	7,979	9,307	8,365	7,594	7,531	7,531
Consumer connection less capital contributions	5,907	1,762	1,705	2,475	2,510	2,510

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	808	1,200	3,100	3,400	-	600
Zone substations	132	500	1,700	3,500	3,800	5,450
Distribution and LV lines	-	-	-	-	-	-
Distribution and LV cables	161	320	1,200	2,000	2,900	500
Distribution substations and transformers	162	500	10	10	10	10
Distribution switchgear	104	260	40	20	600	-
Other network assets	381	970	2,530	1,765	1,660	1,320
System growth expenditure	1,748	3,750	8,580	10,695	8,970	7,880
less Capital contributions funding system growth						
System growth less capital contributions	1,748	3,750	8,580	10,695	8,970	7,880

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
	$000 (in constant prices)					
Subtransmission	343	412	-	-	500	3,000
Zone substations	3,279	550	1,450	2,400	200	200
Distribution and LV lines	8,682	7,452	7,185	7,437	7,265	7,006
Distribution and LV cables	325	761	870	875	881	889
Distribution substations and transformers	6,611	5,332	3,797	3,731	4,065	4,336
Distribution switchgear	2,060	4,714	4,256	4,413	4,373	5,208
Other network assets	518	2,579	2,063	2,742	2,884	2,987
Asset replacement and renewal expenditure	21,816	21,800	19,621	21,598	20,168	23,626
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	21,816	21,800	19,621	21,598	20,168	23,626

11a(v): Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**	$000 (in constant prices)					
Roading Relocations	2,396	1,783	1,801	1,819	1,837	1,874
[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 project or programmes - asset relocations						
Asset relocations expenditure	2,396	1,783	1,801	1,819	1,837	1,874
less Capital contributions funding asset relocations	1,155	1,070	1,081	1,091	1,102	1,124
Asset relocations less capital contributions	1,241	713	720	728	735	750

11a(vi): Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**	$000 (in constant prices)					
Feeder Reliability Improvement	1,949	2,455	1,842	2,017	2,013	2,013
Extreme Event Mitigation	-	-	250	-	-	-
[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 - quality of supply						
Quality of supply expenditure	1,949	2,455	2,092	2,017	2,013	2,013
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	1,949	2,455	2,092	2,017	2,013	2,013

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*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 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
*Project or programme**	$000 (in constant prices)					
BAU Seismic Strengthening	845	1,167	700	300	650	-
Readiness CPP	10,774	4,380				
[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	11,619	5,547	700	300	650	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	11,619	5,547	700	300	650	-

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Software and Licenses	663	650	1,214	1,219	1,025	911
IT Infrastructure	581	570	521	551	455	449
[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	1,243	1,220	1,735	1,770	1,480	1,360
Atypical expenditure						
*Project or programme**						
Readiness CPP	1,518	3,450	-	-	-	-
Capitalised operating leases	1,087	-	-	-	-	790
[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	2,605	3,450	-	-	-	790
Expenditure on non-network assets	3,848	4,670	1,735	1,770	1,480	2,150

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Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2020 – 31 March 2030**

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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	4,771	4,568	4,659	4,752	4,847	4,944	5,043	5,144	5,247	5,352	5,459
11	Vegetation management	1,584	1,837	1,874	1,912	1,950	1,989	2,029	2,069	2,111	2,153	2,196
12	Routine and corrective maintenance and inspection	8,116	9,196	9,588	9,780	9,975	10,175	10,378	10,586	10,798	11,014	11,234
13	Asset replacement and renewal	958	978	997	1,017	1,037	1,058	1,079	1,101	1,123	1,145	1,168
14	**Network Opex**	15,430	16,579	17,118	17,461	17,810	18,166	18,529	18,900	19,278	19,663	20,057
15	System operations and network support	6,460	7,239	7,384	7,531	7,682	7,835	7,992	8,152	8,315	8,481	8,651
16	Business support	10,667	11,723	11,957	12,197	12,441	12,689	12,943	13,202	13,466	13,735	14,010
17	**Non-network opex**	17,126	18,962	19,341	19,728	20,122	20,525	20,935	21,354	21,781	22,217	22,661
18	**Operational expenditure**	32,556	35,540	36,459	37,188	37,932	38,691	39,465	40,254	41,059	41,880	42,718

		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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	4,771	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478	4,478
23	Vegetation management	1,584	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801
24	Routine and corrective maintenance and inspection	8,116	9,016	9,216	9,216	9,216	9,216	9,216	9,216	9,216	9,216	9,216
25	Asset replacement and renewal	958	958	958	958	958	958	958	958	958	958	958
26	**Network Opex**	15,430	16,254	16,454	16,454	16,454	16,454	16,454	16,454	16,454	16,454	16,454
27	System operations and network support	6,460	7,097	7,097	7,097	7,097	7,097	7,097	7,097	7,097	7,097	7,097
28	Business support	10,667	11,493	11,493	11,493	11,493	11,493	11,493	11,493	11,493	11,493	11,493
29	**Non-network opex**	17,126	18,590	18,590	18,590	18,590	18,590	18,590	18,590	18,590	18,590	18,590
30	**Operational expenditure**	32,556	34,843	35,043	35,043	35,043	35,043	35,043	35,043	35,043	35,043	35,043
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	1,449	1,768	1,768	1,768	1,768	1,768	1,768	1,768	1,768	1,768	1,768

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

		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 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	90	181	274	369	466	565	666	769	874	981
43	Vegetation management	-	36	73	110	148	187	227	268	309	351	394
44	Routine and corrective maintenance and inspection	-	180	372	564	760	959	1,163	1,370	1,582	1,798	2,018
45	Asset replacement and renewal	-	19	39	59	79	100	121	143	165	187	210
46	**Network Opex**	-	325	665	1,007	1,356	1,712	2,076	2,446	2,824	3,210	3,603
47	System operations and network support	-	142	287	434	585	739	895	1,055	1,218	1,385	1,554
48	Business support	-	230	464	703	947	1,196	1,450	1,709	1,973	2,242	2,517
49	**Non-network opex**	-	372	751	1,138	1,532	1,935	2,345	2,764	3,191	3,627	4,071
50	**Operational expenditure**	-	697	1,416	2,145	2,889	3,647	4,421	5,210	6,016	6,837	7,674

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Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.06%	0.76%	31.52%	29.23%	38.42%		3	1.57%
11	All	Overhead Line	Wood poles	No.	0.25%	7.39%	73.75%	12.25%	6.35%		3	19.14%
12	All	Overhead Line	Other pole types	No.			53.45%	12.64%	33.91%		4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		5.78%	90.42%	1.12%	2.68%		3	
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km			6.24%	5.41%	88.35%		4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km		30.79%	69.21%				3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	2.25%	17.79%	79.96%				3	9.20%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km		35.96%	64.04%				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.							N/A	
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.		3.55%	70.77%	15.30%	10.38%		3	3.55%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
35												

Row	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.85%	19.23%	75.00%	1.92%			3	3.85%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.02%	16.88%	68.40%	7.58%	7.12%		3	1.56%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km		42.24%	57.68%	0.08%			3	1.00%
42	HV	Distribution Line	SWER conductor	km			100.00%				3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km		0.49%	0.97%	43.15%	55.39%		3	1.00%
44	HV	Distribution Cable	Distribution UG PILC	km	0.10%	3.97%	72.80%	23.08%	0.05%		3	1.00%
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.		3.57%	39.29%	25.00%	32.14%		3	3.57%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	2.59%	2.43%	61.05%	13.71%	20.22%		3	5.02%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.08%	5.67%	76.08%	7.48%	10.69%		3	5.75%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	4.68%	21.91%	66.38%	4.26%	2.77%		3	8.94%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.51%	2.46%	59.60%	18.38%	19.05%		3	2.98%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.33%	1.44%	49.86%	26.21%	22.16%		3	5.11%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.39%	1.44%	55.83%	21.85%	20.49%		3	5.52%
53	HV	Distribution Transformer	Voltage regulators	No.							N/A	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.73%	2.39%	64.83%	14.10%	17.95%		3	1.77%
55	LV	LV Line	LV OH Conductor	km	0.21%	14.19%	82.76%	1.87%	0.97%		2	1.00%
56	LV	LV Cable	LV UG Cable	km	0.02%	8.73%	70.42%	13.63%	7.20%		2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.04%	9.54%	88.56%	1.12%	0.74%		1	1.00%
58	LV	Connections	OH/UG consumer service connections	No.		0.09%	96.22%	1.34%	2.35%		1	2.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	1.35%	4.98%	78.31%	9.53%	5.83%		3	10.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	7.14%	37.97%	8.27%	16.54%	30.08%		3	10.00%
61	All	Capacitor Banks	Capacitors including controls	No.							N/A	
62	All	Load Control	Centralised plant	Lot		8.00%	76.00%	4.00%	12.00%		3	8.00%
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 2020 – 31 March 2030**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	8 Ira Street	15	21	N-1	9	71%	21	86%	No constraint within +5 years	
10	Brown Owl	15	18	N-1	7	83%	18	83%	No constraint within +5 years	
11	Evans Bay	14	19	N-1	11	74%	19	84%	No constraint within +5 years	
12	Frederick Street	27	23	N-1	13	117%	36	83%	No constraint within +5 years	Upgrade 33kV cables
13	Gracefield	12	17	N-1	12	71%	17	71%	No constraint within +5 years	
14	Hataitai	15	22	N-1	11	68%	22	82%	No constraint within +5 years	
15	Johnsonville	20	16	N-1	9	125%	16	144%	Transformer	Peak load control until new Grenada North ZS
16	Karori	15	21	N-1	7	71%	21	86%	No constraint within +5 years	
17	Kenepuru	11	18	N-1	9	61%	18	100%	Subtransmission circuit	Transfer load from Kenepuru to Porirua after Porirua upgrade
18	Korokoro	18	16	N-1	17	116%	15	100%	Subtransmission circuit	Transfer some load from Korokoro to Melling
19	Maidstone	15	18	N-1	12	83%	18	89%	No constraint within +5 years	
20	Mana	9	7	N-1	12	129%	7	129%	Other	Low capacity Mana-Plimmerton bus tie
21	Moore Street	21	30	N-1	14	70%	30	80%	No constraint within +5 years	
22	Naenae	15	18	N-1	11	83%	18	89%	No constraint within +5 years	
23	Nairn Street	21	22	N-1	16	95%	30	83%	No constraint within +5 years	Upgrade 11kV incomer cable capacity
24	Ngauranga	10	10	N-1	10	100%	24	71%	No constraint within +5 years	Upgrade transformer capacity
25	Palm Grove	24	24	N-1	13	100%	36	72%	No constraint within +5 years	Upgrade transformer capacity
26	Plimmerton	8	7	N-1	12	114%	7	129%	Other	Low capacity Mana-Plimmerton bus tie
27	Porirua	21	16	N-1	14	131%	36	61%	No constraint within +5 years	Upgrade 33kV cables, 33/11kV transformers and 11kV bus
28	Seaview	17	14	N-1	12	121%	14	136%	Transformer	Rebalance load between Seaview and Gracefield
29	Tawa	14	16	N-1	13	88%	16	113%	Subtransmission circuit	Peak load control until new Grenada North ZS
30	The Terrace	29	30	N-1	21	97%	30	97%	No constraint within +5 years	
31	Trentham	15	19	N-1	10	79%	19	84%	No constraint within +5 years	
32	University	18	25	N-1	21	72%	25	76%	No constraint within +5 years	
33	Waikowhai Street	14	21	N-1	10	67%	21	67%	No constraint within +5 years	
34	Wainuiomata	17	17	N-1	3	100%	17	118%	Subtransmission circuit	Upgrade 33kV subtransmission cable to raise summer capacity
35	Waitangirua	14	16	N-1	11	88%	16	94%	No constraint within +5 years	Upgrade 33kV cables, 33/11kV transformers and 11kV bus
36	Waterloo	17	20	N-1	14	85%	20	80%	No constraint within +5 years	

37 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

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Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2020 – 31 March 2030**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected in year by consumer type*				**Number of connections**		
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
11		*Consumer types defined by EDB**						
12		Domestic	1,797	1,780	1,804	1,829	1,483	1,499
13		Small Commercial	623	617	625	634	514	519
14		Medium Commercial	17	17	17	17	14	14
15		Large Commercial	23	23	24	24	19	20
16		Small Industrial	5	5	5	5	4	4
17		Large Industrial	-	-	-	-	-	-
18		Unmetered	101	-	-	-	-	-
19		**Connections total**	2,567	2,442	2,475	2,509	2,034	2,057
20		**include additional rows if needed*						
21		**Distributed generation**						
22		Number of connections	200	210	220	231	242	242
23		Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1
24		**12c(ii) System Demand**						
25			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
26		**Maximum coincident system demand (MW)** for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
27		GXP demand	486	499	500	502	503	504
28	*plus*	Distributed generation output at HV and above	64	64	64	64	64	64
29		**Maximum coincident system demand**	550	563	564	566	567	568
30	*less*	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
31		**Demand on system for supply to consumers' connection points**	550	563	564	566	567	568
32		**Electricity volumes carried (GWh)**						
33		Electricity supplied from GXPs	2,125	2,156	2,162	2,168	2,174	2,180
34	*less*	Electricity exports to GXPs	-	-	-	-	-	-
35	*plus*	Electricity supplied from distributed generation	266	241	241	241	241	241
36	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
37		**Electricity entering system for supply to ICPs**	2,391	2,397	2,403	2,409	2,415	2,421
38	*less*	Total energy delivered to ICPs	2,271	2,278	2,284	2,290	2,297	2,304
39		**Losses**	120	119	119	118	118	117
40								
41		**Load factor**	50%	49%	49%	49%	49%	49%
42		**Loss ratio**	5.0%	5.0%	4.9%	4.9%	4.9%	4.9%

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Company Name	**Wellington Electricity**
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Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref								
8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		3.3	5.3	8.5	8.5	8.5	8.5
12	Class C (unplanned interruptions on the network)		28.6	30.1	31.2	31.2	31.2	31.2
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.03	0.02	0.07	0.07	0.07	0.07
15	Class C (unplanned interruptions on the network)		0.45	0.53	0.48	0.48	0.48	0.48

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Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2020 – 31 March 2030**
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	WELL has an Asset Management Policy which is derived from the organisational vision and linked to the organisational strategies, objectives and targets. WELL has also published an Asset Management Strategy (AM Strategy) and associated Fleet Strategies for discreet assets.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	All key components of WELL's AM Strategy are covered in the AMP. Development of Fleet Strategies as well as the overarching AM Strategy has taken into consideration alignment with other organistaional policies and key stakeholders and has had peer review undertaken by industry experts.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	An Asset Management Strategy has been published to cover the total management of assets. Lifecycle Strategies have been developed for primary asset classes, with strategies for distribution substations, distribution swtichgear, and low voltage assets to be published in 2020.		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?	3	Flowing on from the abovementioned Asset Fleet Strategies, WELL is in the process of putting in place comprehensive asset management plans (fleet strategies) that cover all lifecycle activities of the key asset classes, aligned to asset management objectives and strategies.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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Asset Management Standard Applied	

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. All asset strategies are published as controlled documents.		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 documents responsibilities for the delivery actions, and appropriate detail is provided to enable delivery of these actions. Roles and responsibilities of individuals and organisational departments are defined.		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	WELL's plans are realistic in terms of the resources required and achievable timescales. They capture any changes required to policies, strategies, standards, processes and information systems.		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	WELL has a suite of appropriate Emergency Response Procedures and Contingency Plans in place to mitigate and manage the impact of potential High Impact Low Probability events. These are listed and described in Section 11 of this AMP. These plans get tested in simulated major event situations.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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 flows from the CEO through the GM Asset Management, to the 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			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 the annual AMP disclosures, and through weekly and monthly meetings with management teams and service providers.		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	WELL outsources a number of asset management activities, particularly with Service Delivery responsibilities. These are described in Section 4 of this AMP. Comprehensive contracts and performance measures are in place to ensure efficient and cost-effective delivery of these activities.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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	WELL can demonstrate that role descriptions are in place for all staff required to conduct asset management functions, and that these roles are filled with appropriately qualified personnel.		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	Position descriptions are in place for all staff required to conduct asset management functions. Staff undertake training and development where required to ensure they can deliver on the requirements of the AMP. Work competencies are listed for all main contracting activities, and WELL monitors and ensures that the Contractors' staff have, and maintain their competencies.		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	Training requirements are identified at the start of the year, and reviewed every six months during staff performance reviews. Work competencies are listed for all main contracting activities, and WELL monitors and ensures that the Contractors' staff have, and maintain their competencies.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	In addition to the annual AMP disclosure, regular contract meetings are held between Safety, Asset Management and Service Delivery Managers and the respective service providers. In addition specific asset management is communicated between employees and contractors through safety alerts, technical alerts, network instructions, and at technical forums.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Asset Management documentation and control is in place, and is described in Section 4 of the AMP.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Asset Management information systems are in place, and these are listed and described in Section 10 of this AMP. They include SCADA, GIS and SAP. Support for these systems is provided by CHED Services.		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	Contols are are place in the form of data quality standards to manage the quality and accuracy of the data entered into the asset management information systems. Processes for QA and audit of data are in place.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Asset Management requirements were fully reviewed during development of the business case to implement SAP-PM, and to upgrade GIS ensuring that they meet Asset Management needs. The systems have been reviewed at various times by CHED auditors, Jacobs, PwC, and other external specialists.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	In January 2016, WELL aligned its risk approach with that of CKI by adopting the Enterprise Risk Management (ERM) – Integrated Framework Risk Management Principles and Guidelines Standard. This provides a structured and robust framework to managing risk, which is applied to all business activities, including recently published Fleet Strategies.		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 various meetings and other communications.		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	WELL has staff in its office that are responsible for Legal, Regulatory, Statutory and other asset management requirements.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Consultants are often used to assist during the design stage. Scope of work is clearly defined and controlled through a Short Form Agreement. Procurement is controlled through an approved materials standard. Construction and commissioning activities are outsourced, and these are carefully controlled through contracts with the service providers.		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 an inspection and maintenance plan in place with remedial actions derived from the 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?		WELL annually rates all assets against Asset Health Indicators that is based on the AHI's guideline published by the EEA. In addition WELL has developed Criticality indices to further inform the risks of each asset. This is used to measure the performance and condition of its assets. This is informed by the results of the inspection and maintenance programme conducted by its maintenance service provider at frequencies and according to procedures detailed in maintenance standards. The AHI & ACI analysis in turn assists with the development and update of the Fleet Strategies and replacement programmes.		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	WELL has procedures which clearly outline the roles and responsibilities for managing major incidents 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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.

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Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2020 – 31 March 2030**
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))?	3	CKI has internal auditors in CHED Services in Melbourne that select two areas to do comprehensive audits on each year. Further to this WELL has had its Asset Management activities and processes reviewed by Jacobs with a positive outcome and report.		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	Incident and root cause analysis investigations and corrective actions involve both WELL and its service providers, and are logged, reviewed and discussed at weekly & bi-weekly meetings. A package called 1Fics is used to track and keep information relating to all incidents and corrective actions until they have been completed and the incident closed out.		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	The Asset Fleet Strategies detail asset-specific strategies for meeting the asset management objectives. These documents analyse the performance, and condition of assets across the whole life cycle, as well as maintenance and replacement costs, and any associated asset-related risks. They are controlled documents on an annual review cycle, with this update process ensuring that continual improvement in the management of asset performance, condition, costs, and risks. Completion of the remaining strategies is required to achieve Maturity Level 3.		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, WELL places a high level of importance on learnings that can be made from its sister companies within the group, and from within the industry in New Zealand. There are video conferences held between sister companies to discuss the latest in AM practices from across the world.		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.

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Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018)

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

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:

There is no difference between constant and nominal values in the current disclosure year ended 31 March 2020.

The difference from 2020/21 to 2029/30 represents inflation and is 2.0% per annum across the planning period.

The rates are based on the midpoint of the RBNZ's 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

There is no difference between constant and nominal values in the current disclosure year ended 31 March 2020.

The difference from 2020/21 to 2029/30 represents inflation and is 2.0% per annum across the planning period.

The rates are based on the midpoint of the RBNZ's target inflation range.

Appendix D Network Development Options

This section summarises the options considered for the major network constraints identified in Section 8.4-8.6.

Southern Area

Frederick Street – Issue A1I1

The following options were considered to resolve the subtransmission constraint at Frederick Street detailed in Section 8.4.2.3. The Board approved Option A1I1-5 in 2019.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A1I1-1	Do nothing	nil	Lowest	No need to invest any capital.	Continued operation with inadequate security of supply–operating outside WE*security of supply criteria; and high risk of damage to sub transmission cables due to risk of potential protection mal-operation and due to overload at peak should one circuit be out of service.
A1I1-2	Protection upgrade only	0.4	Low	Low cost option, addresses the existing risk with poor protection system upgrade.	Continued operation with security of supply–operating outside WE*security of supply criteria at peak times; and high risk of damage to sub transmission cables due to overload at peak should one circuit be out of service. Network does not meet WE*security of supply criteria at peak times.
A1I1-3	Demand side management, protection upgrade and deferred cable upgrade	9.8	Highest	The option has potential to utilise emerging technology to improve asset utilisation as some of the demand is shifted from peak to off-peak and use of the full life of the assets; and could defer investment in new cables	Not enough load reduction capacity to meet security requirements (ripple load control already in place and will not further contributes towards reduction in peak demand), and potential saving from deferred cable investment too small to fund demand management.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A1I1-4	Install one new cable, parallel the existing two cables and protection upgrade	9.5	Moderate	Addresses the protection and security of supply risk, while allowing utilisation of remaining life of existing cable.	Continued reliance on old cable technology with increasing risk of failure due to aging. Misses out the cost saving benefits of coordinated work–the second cable circuit still needs to be replaced in the near future and deferred cost of second cable very small yet the install cost of second cable as high as that of the first cable.
A1I1-5	Install two new cables following the same route and protection upgrade	7.3	Moderate	Addresses the existing security of supply risk–resolves the protection and sub transmission overloading issues at peak times. Also provides an opportunity to connect a new CBD zone substation in future to support future load growth. The only option with positive NPV.	Cables in the same route at risk of common mode failures. Mitigated over time by proposed eastern 33kV ring.
A1I1-6	Two new cables with route diversity and protection upgrade	11.7	High	Resilience against common mode failures. Higher cost option compared to option 5.	The largest cost component is establishing a second cable route, therefore diverse routes lead to a significant increase in project cost.

The Terrace – Issues A1I3 and A1I4

The following options are being considered to resolve the expected future subtransmission and transformer constraints at The Terrace detailed in Section 8.4.2.9.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A1I3-1	Demand response	2.0/yr	High	The option has potential to utilise emerging technology to improve asset utilisation as some of the demand is shifted from peak to off-peak and use of the full life of the assets; and could defer investment in new cables	Not enough load reduction capacity to meet security requirements (ripple load control already in place and will not further contribute towards reduction in peak demand), and potential saving from deferred investment too small to fund demand management.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A1I3-2	Replace 30MVA transformers to 36MVA to match the 11kV incomer CB and bus rating	6.0	Moderate	Assured capacity for existing and growing load in the CBD	Low MVA gain for the amount of investment, risk of single point of failure to have a highly loaded zone sub. Access constraints into transformer rooms complicate the project.
A1I4-2	Upgrade Terrace cable capacity	3.0	High	Assured capacity for existing and growing load in the CBD	Does not make use of the approved Frederick Street sub-transmission capacity upgrade
A1I3-3	Permanently transfer some load away (to University, Frederick Street (after cable upgrade), Kaiwharawhara)	0.1	Moderate	Utilise the upgraded capacity at Frederick Street.	Not introducing any new capacity to the network
A1I3-4	Build new Bond Street ZS in 2029 (lay ducts with LGWM, else cable cost higher), 33kV cable between Terrace and Bond Street, Cut and extend Frederick Street cables, 33kV bus at Frederick Street and Terrace.	33	Moderate	Caters for growing CBD load - new buildings and transport electrification.	High cost of laying cable in the CBD

Evans Bay – Issue A2I1

The following options were considered to improve security of supply into Evans Bay due to the leaking Evans Bay 1 cable. The Board approved Option A2I1-6 in 2020.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I1-1	Manage risk reactively–continue maintenance and operate to failure.	0.2/yr	Low	No initial investment needed	Significant on-going maintenance cost and potential risk of failure and outages with potential reliability (SAIDI/SAIFI) penalties. Cable replacement cannot be completely avoided Major cost to deliver replacement project under contingency

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I1-2	Decommission the cable in poor condition and supply Evans Bay from a single transformer and reinforced 11 kV ties to Ira Street	3.0	Moderate	Meets the existing capacity needs Defers replacement of Evans Bay circuits by approximately 7 years before hitting capacity issue	EVA 2 circuit deterioration would be accelerated when operating with double the existing load Reduced network security and much longer restoration time compared to the current configuration Cause capacity and security issues at adjacent substations that will have to bear additional load during Evans Bay contingency, and loss of backup capacity from Evans Bay High implementation cost of buried cable installation. Limits growth at Evans Bay and Ira Street Cable replacement cannot be completely avoided, only deferred
A2I1-3	Replace the existing gas filled Evans Bay cables with two new 33kV XLPE cables	15.4	Moderate	New assets will provide improved reliability and greater capacity for future growth.	Significant CAPEX investment is required. Complexity of buried cable installation in the city adds to the project cost. Resiliency concerns due to radial configuration of the sub-transmission circuits remains.
A2I1-4	Establish IRA 1 – EVA Transformer A tee-off via outdoor switchgear to enable changeover after cable failure	1.5	High	Low initial cost Defers need for a full bus by about 5 years and replacement of Evans Bay circuits by about 7 years	Complex protection and inter-tripping arrangement means increasing the risk of protection mal-operation on both EVA and IRA substations Cannot build on the solution for further sub-transmission development in the area. To build full bus will have to remove the outdoor arrangement to create space for the switchroom, which will be highly complex due to post-event system security requirements. Will not be possible to wait for the construction of a new cable due to its long construction period and lead time. Add a significant amount of load on IRA 1 circuit with security and capacity risks

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I1-5	Half 33kV indoor bus at Evans Bay–build a switchroom sized for a full bus and install only half bus to tap into Ira 1 cable and connect EVA transformer TA	3.3	Moderate	Utilising the existing 4 circuits to avoid cable replacement Offers operational flexibility and building block for a full bus–the half bus does not end up sunk cost as the future full 33kV bus development will build on the half bus: - requires no site modifications after an event to enable full 33kV bus construction - switchboard extension without de-energising the live section maintaining system security Less pressure on contingency arrangement if EVA Circuit 1 has a catastrophic failure A spare feeder bay will also enable mobile sub connection and can be reused for Hataitai connection.	Need to develop full size switchroom in the first phase WE* will need develop capacity to operate 33 kV switchgear.
A2I1-6	Full 33 kV indoor bus supplied from the Ira Street cables and the healthy Evans Bay 2 cable, to supply Evans Bay and Ira Street zone substations –build a new switchroom and install a full bus to connect three healthy 33 kV circuits at Evans Bay, abandon EVA 1 feeder	4.5	Moderate	Full solution–requires no further actions on the site. Offers operational flexibility and sufficient N-1 capacity for growth. Defer replacement of Evans Bay circuits by about 10 years Avoids need to troubleshoot and repair old gas filled cable. Building block for future network configuration The full bus also improves sub transmission security to Ira Street and Hataitai Allows option to reuse the healthy sections of the Evans Bay cables to connect Hataitai–provide alternative supply to HAI from EVA bus, resolve the capacity and condition issues at HAI and provide extra redundancy to EVA	Moderately high initial cost but overall CAPEX economical. WE* will need develop capacity to operate 33 kV switchgear. Abandon the EVA 1 circuit with sections that may still has some limited useful life but this is difficult to assess

Karori – Issue A1I8

The following option is being considered to resolve the expected future subtransmission constraint at Karori detailed in Section 8.4.2.5.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A1I8-1	Transfer more load to University through UNI8/10 and UNI 1/6 rings.	Nil	Low	Low cost balancing between zones.	

Palm Grove – Issue A2I3

The following options are being considered to resolve the transformer constraint at Palm Grove detailed in Section 8.4.2.8.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I3-1	Upgrade PAL transformer capacity - replace existing with 36MVA units.	4.5	Moderate	Lift Palm Grove transformer constraints, improve branch rating to 36MVA, resolve acoustic issues at site.	
A2I3-2	Transfer some Palm Grove load to Hataitai through a new tie point at hospital	0.6	Moderate	Opportunity to coordinate with customer projects - Wellington hospital expansion	Customer has signalled in 2019 that we have funding issues to improve capacity or security, it is likely to be within the same timeline
A2I3-3	Battery Storage	4	Moderate	Resiliency improvement if installed at a remote location	High cost and limited life time

Nairn Street – Issue A2I5

The following options are being considered to resolve the expected future incomer constraint at Nairn Street detailed in Section 8.4.2.7.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I5-1	Increase incomer capacity by running additional 630 mm^2 Cu cables + new incomer CB - lay the cables in ducts installed with the Frederick Street cable project	0.4	Moderate	Opportunity to coordinate work with Transpower switchgear replacement.	
A2I5-2	Transfer load away from Nairn Street to adjacent zone substations	0.1	Low		

Hataitai – Issue A2I7

The following options are being considered to resolve the expected future subtransmission constraint at Hataitai detailed in Section 8.4.2.4.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I7-1	Upgrade subtransmission cable capacity: identify and remove pinch points.	1	High	Targeted work to increase capacity of existing cable without requiring its full replacement.	
A2I7-2	Upgrade subtransmission cables - install 2x 800mm2 Al XLPE from EVA 33 kV bus, approx. 2.5km	7	High	Shorter upgrade than overlaying the existing Hataitai cables.	Increases the criticality of the Ira Street oil-filled cables.
A2I7-3	Upgrade subtransmission cables - install 2x 800mm2 Al XLPE from CPK, approx. 3.1km	9	High	Removal of gas cable from the network.	High cost, follows existing difficult route through Mt Victoria tunnel.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
A2I7-4	Upgrade subtransmission cables - install 2x 800mm2 Al XLPE from EVA 33 kV bus, approx. 2.5km, and create 33kV bus at Hataitai.	11	High	Creates a subtransmission ring: CPK-EVA-HTI-CPK. Increases security of supply into Evans Bay. Retains existing good condition Hataitai cables.	High cost.

Northwestern Area

Johnsonville – Issues B1I2 and B1I3

The following options are being considered to resolve the subtransmission and transformer constraints at Johnsonville detailed in Section 8.5.2.1.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I2-1	Upgrade Johnsonville transformer capacity - replace existing transformers with 36MVA units.	5	Moderate		Leads to a high capacity JOH substation that is difficult to backup.
B1I3-1	Replace existing JOH 33kV cable with 1000mm^2 Al XLPE cables, approx. 5km while retaining existing sub-transmission circuit configuration. The project may be ARR driven due to condition issue	8	Moderate		
B1I2-2	Upgrade Ngauranga transformer capacity – Option B1I7-2	2	Moderate	The option resolves and/or delays a number of issues: - NGA transformer capacity issue, - NGA transformer condition issue, - JOH 6 capacity issue, - KAI 6/7/9/10 ring feeder capacity, - delay JOH transformer capacity issue, - delay KAI GXP transformer capacity issue, and - provides more capacity to back up JOH	

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I2-3	Develop Grenada North zone substation supplied from first TKR-KDH line section. Upgrade 11kV ties to supply Ngauranga and Johnsonville from Grenada. This could be linked to a ARR JOH cable upgrade, which will provide a bus and 11kV feeders along the new 33kV cable route	20	High	Avoids the high maintenance cost and safety risks associated with the existing TKR-KDH tower line. It improves reliability and utilisation of the sub-transmission circuits into the subregion. The option improves reliability by addressing the existing condition and capacity issues of the JOH cables, the 33/11 kV transformers in the subregion. The option can be delivered in stages therefore delays need for immediate upgrade of Tawa ZS and re-establishment of Ngauranga ZS. Provide capacity for the Churton Park and Grenada North growth areas between Tawa and JOH currently served by a rural feeder that is already at capacity while improving reliability by providing better transfer capability between zone substations.	Still need a zone substation at Ngauranga to back up Johnsonville and to limit the size of Johnsonville zone substation. Difficult cable routes including crossing SH1.
B1I3-3	New GRE - JOH Cable instead of TKR - JOH, terminate one of the existing 33kV circuits to GRE bus, The project may be ARR driven if cable leaks reoccur.	8	Moderate		Reduced redundancy

Kenepuru – Issue B2I1

The following options are being considered to resolve the forecast subtransmission constraint at Kenepuru detailed in Section 8.5.2.2.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I1-1	Transfer load to adjacent Porirua zone substation after more capacity is created at Porirua	0.1	High	Minimise the impact at Kenepuru, use additional capacity introduced by Porirua which is a centralised solution for the area	No capacity margin at the adjacent zone sub

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I1-2	Resolve pinch point along the cable route to resolve summer constraints	1.5	Moderate		
B2I1-3	Replace existing 240mm^2 Kenepuru 33kV cable with 1000mm^2 Al XLPE cables, approx. 770m.	2.5	Moderate		SH1 crossing

Ngauranga – Issue B1I1

The following options are being considered to resolve the expected transformer constraints at Ngauranga detailed in Section 8.5.2.3.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I1-1	Replace the existing TKR-KDH line supplying Ngauranga with a 33kV pole line following the same route. This project would be a Transpower project but WELL would still need to allocate cost for secondary assets replacement and rectify the limitations on the current one way inter-trippng scheme. 33kV CBs will be decommissioned after project completion	0.7	High	This option retains Ngauranga zone substation which will provide backup to Johnsonville, pick up some of Kaiwharawhara load off Station Road (Abattoirs) and continue supplying existing Ngauranga load. The new pole line avoids the high maintenance cost associated with the existing tower line. The new line will be appropriately rated to serve existing and forecast load; and can also be used to supply Grenada North in the future.	Retains the entire load for the subregion at Takapu Road GXP and the radial 33kV sub-transmission circuits. Future load growth is forecast towards the north and this option reinforces capacity away from the centre of load growth requiring significant reinforcement of 11 kV feeders to supply the growth areas.
B1I1-2	Convert Ngauranga to an 11kV switching station supplied from Johnsonville. Upgrade the TKR-JOH cable and 33/11 kV transformers; and upgrade 11kV ties to supply NGA from JOH.		High	Low initial cost	Still need a zone substation at Ngauranga to back up, and limit the size of, Johnsonville zone substation. Increases the criticality of Johnsonville zone substation.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I1-3	Build a 33kV bus at Johnsonville to supply both Johnsonville and Ngauranga, bring forward TKR-JOH cable replacement and develop new 33 kV JOH-NGA circuits.		High	Avoids the high maintenance cost associated with the existing tower line. The option improves reliability by addressing the existing capacity and improves utilisation of TKR-JOH overhead circuits. The option also addresses the capacity and condition of the 33/11 kV transformers in the subregion.	Retains the entire load for the area at Takapu Road GXP and it is not easy to build on this option to cater for future growth. Load growth may lead to reliance on two 33 kV subtransmission circuits to carry more than 60 MVA of load leading to high consequence of failure.
B1I1-4	Supply Ngauranga from Kaiwharawhara at 33 kV – Replace existing Kaiwharawhara transformers with 110/33/11kV units and install 33 kV cables to NGA.		High	Avoids the high maintenance cost associated with the existing TKR-KDH tower line. The option improves reliability by addressing the existing capacity issues of the Johnsonville cables and the 33/11 kV transformers in the area It diversifies the GXPs supplying the area by shifting load away from Takapu Road.	Reinforces capacity away from the centre of the load growth area. It will be difficult to obtain access to the line corridor currently used for the TKR-KDH line once it has been relinquished. Load growth may lead to need for significant reinforcement of 11 kV feeders to supply the Grenada North and Churton Park growth areas.
B1I1-5	Develop Grenada zone substation supplied from first TKR-KDH line section. Upgrade 11kV ties to supply Ngauranga and Johnsonville from Grenada. This is linked to the Johnsonville 33kV cable upgrade, which would provide a bus and 11kV feeders along a new 33kV cable route	20	High	Avoids the high maintenance cost associated with the existing TKR-KDH tower line. The option improves reliability by addressing the existing capacity issues of the Johnsonville cables and the 33/11 kV transformers in the area. The option can be delivered in stages therefore delays need for immediate upgrade of Tawa ZS and re-establishment of Ngauranga ZS. Provide capacity for the Churton Park and Grenada North growth areas between Tawa and Johnsonville currently served by a rural feeder that is already at capacity while improving reliability by providing better transfer capability between zone substations.	Still need a zone substation at Ngauranga to back up, and limit the size of, Johnsonville zone substation. Difficult cable routes including crossing SH1.

Mana – Issue B3I3

The following options are being considered to resolve the 11kV bus tie constraint at Mana detailed in Section 8.5.2.4.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B3I3-1	Install a second transformer and 11kV bus section at Mana, 33kV bus Plimmerton and a new 33kV circuit from Plimmerton to Mana.	12	Moderate		Limited space on the site, high cost.
B3I3-2	Upgrade the Mana-Plimmerton 11 kV bus-tie: install a second cable in parallel with the existing after Plimmerton has a second TX. This will ensure spare Subtransmission is available from Plimmerton	4.5	High	Increase the N-1 Mana capacity to 14MVA or the remaining capacity at Plimmerton, whichever is lower	Only can build on top of the Plimmerton 2nd TX solution
B3I3-3	Establish new 11 kV GXP at Pauatahanui and transfer some of Mana load to Pauatahanui - replace existing PNI supply transformers with 2x 110/33/11kV transformers and build 11kV ties to connect existing MAN2 feeder (approximately 2km of 11kV cable).	2.0 + 8.0 TP pass through	Moderate		Depends on Transpower plans to be viable
B3I3-4	Reinforce 11kV feeders to enable load transfer from Mana to Porirua and Plimmerton after their upgrade. Mana will be used to supply the remaining load and pick up more load from Titahi Bay	4.0	Moderate	Reduce Mana load and improve connectivity on all nearby subs	Depends on other zone substation upgrades
B3I3-5	Install a new 11kV feeder from Porirua - Mana and a 33kV ring from Porirua to Plimmerton	8.0	High	Reliability and also reduce loading on MAN bus	Cost and complexity

Plimmerton – Issue B3I2

The following options are being considered to resolve the 11kV bus tie constraint at Plimmerton detailed in Section 8.5.2.5.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B3I2-1	Install a 33kV bus, a second 24MVA transformer and a second 11kV bus section at PLI. This will introduce a N-1 firm rating of 16MVA at PLI and ensures spare capacity is avaiable to MANA during a TX outage at MAN	8	High	a 33kV bus will furthur increse the ability to supply the new load around PLI farm and northern areas. This can be triggered by the customer project development	
B3I2-2	Upgrade the MAN-PLI 11 kV bus-tie: install a second cable in parallel with the existing.	4.5	High	Increase the bus tie cable to 14MVA	The actual available MVA from MAN is still limited to 16 - MAN load, which is only around 7
B3I2-3	Establish new 11 kV GXP at PNI and transfer some of PLI load to PNI - replace existing PNI 2winding supply transformers with 2x 110/33/11kV 3winding transformers and build 11kV ties to connect existing PLI11 feeder (approximately 50m of 11kV cable).	2.8 (plus $8 million Transpower pass through)	High		Depends on Transpower plans to be viable

Porirua – Issue B2I2

The following options are being considered to resolve the subtransmission constraint at Porirua detailed in Section 8.5.2.6.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I2-1	A complete upgrade of the Porirua 33kV cable, transformers, and switchboard, for a site N-1 capacity of 36MVA	16	High	Provides capacity for the existing and future load at Porirua. The upgraded zone substation improves supply security by providing improved offload options for adjacent ZS.	Complex project co-ordination and risk control in project delivery when working on existing assets. Reduced supply security during changeover. The option increases criticality of the ZS assets.
B2I2-2	Transfer load to adjacent ZS (WTG, KEN)	0.1	Moderate	Low cost	No capacity margin at the adjacent ZS
B2I2-3	Develop new ZS with 33kV bus at Cannons Creek and supply some of POR load to avoid need for upgrade at POR	23	High	Addresses existing capacity issues at POR– reduces loading on the 33kV cables and transformers and releases capacity for growth	A new ZS dependent on land availability in the preferred location (discuss opportunity with HNZ as they may be able to help in securing land for the ZS)

Tawa – Issue B1I5

The following options are being considered to resolve the forecast transformer constraint at Tawa detailed in Section 8.5.2.7.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B1I5-1	Same as B1I1-5 – Grenada Zone Substation				
B1I5-2	Upgrade TAW transformer capacity to 2x 24MVA units.	5.0	Moderate	Addresses existing issue and caters for load growth	Requires
B1I5-3	Same as B1I3-1 – Upgrade				

Waitangirua – Issues B2I7 and B2I8

The following options are being considered to resolve the forecast future subtransmission and transformer constraints at Waitangirua detailed in Section 8.5.2.8.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
B2I7-1	Upgrade Waitangirua transformer capacity to 2x 30MVA units	4.0	Moderate		
B2I8-1	Upgrade Waitangirua subtransmission capacity - replace cable with 1000mm^2 Al XLPE, approx. 1.4km	4.0	Moderate		
B2I7-2/ B2I8-2	B2I2-1 - complete upgrade of the Porirua zone substation	16	High	Avoids upgrade of Waitangirua.	
B2I7-3/ B2I8-3	Establish new 11 kV GXP at Pauatahanui and transfer some of Waitangirua load to new sub	2.0 + 8.0 pass through	Moderate	Avoids upgrade of Waitangirua and release capacity at Waitangirua to back up Porirua.	Pauatahanui is located further east of the load centre than would be optimal.

Northeastern Area

Korokoro – Issues C1I1 and C1I2

The following options have been considered to resolve the subtransmission and transformer constraints at Korokoro detailed in Section 8.6.2.4. Option C1I1-1 is planned to be implemented in 2021. Growth in the area will continue to be monitored to see whether additional options need to be implemented.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
C1I1-1	Transfer some of Petone load away to Melling using the deenergised Petone 33kV cable at 11kV. Split the Petone 11kV bus with one half supplied from Korokoro and the other from Melling.	1.2	Moderate	Delays need for upgrading the Korokoro sub-transmission cables, enable about 4.5MVA of load transferable between GFD GXP and MLG GXP	Reuse the 33kV gas filled cable and relying on a solution that is prone to aging failure

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
C1I1-2	Replace Korokoro sub-transmission cables, approx. 5.2km	8.0	Moderate	New cables and the supply can come from MLG instead of GRA.	High Cost, cable route follows The Esplanade.
C1I1-3	Re-establish Petone 33kV zone substation, new 33kV transformers, cables and pick up some of Korokoro load	15	Moderate	Avoids need to upgrade Korokoro subtransmission cables	High cost, requires replacing the Petone 33kV cables and re-establishing two previously relinquished 33kV connections at Melling.
C1I2-1	Upgrade Korokoro transformers - replace existing with 36 MVA units. Also need to replace 11kV board with 2000A incomers	7	Moderate	Introduce new capacity to the Korokoro area	High Cost

Seaview – Issue C1I8

The following options are being considered to resolve the subtransmission constraint at Seaview detailed in Section 8.6.2.8.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
C1I8-1	Rebalance load between Seaview and Gracefield.	0.1	Low	Low cost balancing between zones.	Does not increase capacity in the area.
C1I8-2	Replace Seaview 33 kV PILC cables, 1.5km	3.0	Moderate	Release existing transformer capacity.	Cables in good condition.

Wainuiomata – Issues C1I3 and C1I5

The following options are being considered to resolve the forecast subtransmission and transformer constraints at Wainuiomata detailed in Section 8.6.2.10.

Option ID	Option Description	Cost ($M)	Complexity	Pros	Cons
C1I3-1	Monitor load growth and manage peak loading via operational control and demand response program	1.2	High		Large volume of demand response required to offset forecast load growth. High cost relative to the Network options.
C1I3-2	Install 1MVA generator to reduce peak demand	0.8	Moderate	Addition of generation improves resilience of the supply in the area	Installation of diesel generation does not align with decarbonisation aspiration.
C1I3-3	Upgrade Wainuiomata subtransmission cable, approximately 150m, complete this task as part of the TP GFD IDID upgrade	0.4	Moderate	Resolves the subtransmission constraint	Wainuiomata will be on N security during delivery with not enough offload capacity should the in-service circuit fail.
C1I5-1	Demand side response to reduce Wainuiomata TB capacity issue	0.2/year	Moderate	Resolves capacity issue	Not a secure solution.

Appendix E Summary of AMP Coverage of Information Disclosure Requirements

Information Disclosure Requirements 2012 clause	AMP section
3.1 A summary that provides a brief overview of the contents and highlights information that the **EDB** considers significant	1
3.2 Details of the background and objectives of the **EDB**'s asset management and planning processes	4.1, 4.2
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**	4.1
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	4.1
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
3.4 Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed	2
3.5 The date that it was approved by the **directors**	2
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** 3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured 3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	3.2.2, 3.2.4.1 3.2.3 & 3.2.5 3.2.5 & 4.3.1
3.8 All significant assumptions: 3.8.1 quantified where possible 3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including 3.8.3 a description of changes proposed where the information is not based on the **EDB**'s existing business 3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information 3.8.5 the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Appendix A Appendix A Appendix A Appendix A Schedule 14a
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	1.3-1.4, 9.4, 9.6 & Appendix A
3.10 An overview of asset management strategy and delivery	4.1, 4.3
3.11 An overview of systems and information management data	10.1
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	10.3

safer together

Information Disclosure Requirements 2012 clause	AMP section
3.13 A description of the processes used within the **EDB** for- 3.13.1 managing routine asset inspections and **network** maintenance 3.13.2 planning and implementing **network** development projects 3.13.3 measuring **network** performance.	 7.4, 10.1.1.8 8.2 5.2.2
3.14 An overview of asset management documentation, controls and review processes	4.4
3.15 An overview of communication and participation processes	3.6, 5.4.1
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	2.4
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.	5.2, 4.2, 7 & 8
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.	 3.3 3.4 3.5 3.5 & 8.2 3.5

Information Disclosure Requirements 2012 clause	AMP section
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;	3.4
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;	3.4, 8.4–8.6
4.2.3 a description of the distribution system, including the extent to which it is underground;	3.4, 7.5.4
4.2.4 a brief description of the **network**'s distribution substation arrangements;	3.4, 7.5.5
4.2.5 a description of the **low voltage network** including the extent to which it is underground; and	3.4, 7.5.4
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	7.5.8
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	N/A
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;	3.4, 7.5
4.4.2 description and quantity of assets;	7.1
4.4.3 age profiles; and	7.5
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.	7.5

Information Disclosure Requirements 2012 clause	AMP section
4.5 The asset categories discussed in subclause 4.4 above should include at least the following-	
4.5.1 Subtransmission	7.5.1
4.5.2 Zone substations	7.5.2
4.5.3 Distribution and LV lines	7.5.3
4.5.4 Distribution and LV cables	7.5.4
4.5.5 Distribution substations and transformers	7.5.5
4.5.6 Distribution switchgear	7.5.6, 7.5.7
4.5.7 Other system fixed assets	7.5.8
4.5.8 Other assets;	7.5.9
4.5.9 assets owned by the **EDB** but installed at bulk electricity supply points owned by others;	7.5.10
4.5.10 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	7.5.9.2
4.5.11 other generation plant owned by the **EDB**.	7.5.9.2
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**.	5
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**.	6.1
7. Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1 **Consumer** oriented indicators that preferably differentiate between different consumer types;	5.4
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.	5.3, 7.5
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.	5, 6.1

Information Disclosure Requirements 2012 clause	AMP section
9. Targets should be compared to historic values where available to provide context and scale to the reader.	5
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.	6
Network Development Planning 11. **AMP**s must provide a detailed description of **network** development plans, including— 11.1 A description of the planning criteria and assumptions for **network** development;	8.1,8.2
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;	8.1, 8.2
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;	8.1.6
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.	7.2 & 8.1.6 7.2 & 8.1.6
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	8.1.7
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**.	8.1.10
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.	4.2

Information Disclosure Requirements 2012 clause	AMP section
11.8 Details of demand forecasts, the basis on which they are derived, and the specific **network** locations where constraints are expected due to forecast increases in demand;	
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	8.2.1
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;	8.4-8.6
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	8.4-8.6
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.	8.1.9
11.9 Analysis of the significant **network** level development options identified and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described; 11.9.3 consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment.	Appendix D
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;	8.4-8.7
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	8.4-8.7
11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**.	8.4-8.7
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.	8.1.9
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	8.1.8
11.12.2 the potential for non-network solutions to address **network** problems or constraints.	8.1.8

Information Disclosure Requirements 2012 clause	AMP section
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including—	
12.1 The key drivers for maintenance planning and assumptions;	7.4 & 7.5
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;	7.5
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	7.5
12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**.	7.6
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;	7.2, 7.5
12.3.2 a description of innovations made that have deferred asset replacement;	7.5
12.3.3 a description of the projects currently underway or planned for the next 12 months;	7.5
12.3.4 a summary of the projects planned for the following four years (where known); and	7.5
12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**.	7.5–7.6
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.	Yes
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;	10.1-10.6
13.2 development, maintenance and renewal policies that cover them;	10.4–10.6
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	10.4
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	10.7

Information Disclosure Requirements 2012 clause	AMP section
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.	4.7 11.4 4.7.3, 11.4 11.3
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;	5
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.	4.5
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.	4.5
<u>Capability to Deliver</u> 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

Appendix F Glossary of Abbreviations

AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
ADSS	All Dielectric Self Supporting
ACI	Asset Criticality Indicator
AHI	Asset Health Indicator
AMI	Advanced Metering Infrastructure
ANM	Advanced Network Management
BRMP	Business Recovery Management Plan
Capex	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
CCT	Covered Conductor Thick
CDEMA	Civil Defence and Emergency Management Amendment Act (2016)
CEO	Chief Executive Officer
CIA	Cyber Security and Data Confidentiality, Integrity and Availability
CIC	Capital Investment Committee
CKI	Cheung Kong Infrastructure Holdings Limited
CMP	Crisis Management Plan
CPI	Consumer Price Index
CPP	Customised Price Path
CPRG	Constant Price Revenue Growth
CT	Current Transformer
Cu	Copper
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DMS	Distribution Management System
DNO	Distribution Network Operator
DP	Degree of Polymerisation
DPP	Default Price-quality Path
DR	Demand Response
DSA	Detailed Seismic Assessment
DSO	Distribution System Operator
DTS	Distributed Temperature Sensing
EDB	Electricity Distribution Business

EDO	Expulsion Drop-out Fuse
EEA	Electricity Engineers Association
EECA	Energy Efficiency and Conservation Authority
EEP	Emergency Evacuation Plan
EIPC	Electricity Industry Participation Code
EMS	Energy Management System
ENA	Electricity Network Association
ENMAC	Electricity Network Management and Control
ERP	Emergency Response Plan
ESO	Energy System Operator
ETR	Estimated Time of Restoration
EV	Electric Vehicle
FDIR	Fault Detection, Isolation and Restoration
FPI	Fault Passage Indicators
GWh	Gigawatt Hour
GIS	Geographical Information System
GXP	Grid Exit Point
HCC	Hutt City Council
HILP	High Impact Low Probability
HLR	High Level Request/Response
HSE	Health, Safety and Environmental
HSW	Health and Safety Work Act (2015)
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
IPS	Intruder Prevention System
ISO	International Standards Organisation
IoT	Internet of Things
IIoT	Industrial Internet of Things
IT	Information Technology
ITRP	Information Technology Recovery Plan
km	Kilometre
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light Emitting Diode
LEVCF	EECA's Low Emission Vehicle Contestable Fund

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
MBIE	Ministry of Business Innovation and Employment
MEMP	Major Event Management Plan
MEFRP	Major Event Field Response Plan
MEUG	Major Electricity Users Group
MUoSA	Model Use of System Agreement
MW	Megawatt
MWFM	Mobile Workforce Management
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
OCB	Oil Circuit Breaker
OD-ID	Outdoor to Indoor conversion
ODV	Optimised Deprival Value/Valuation
O&M	Operating and Maintenance
OLTC	On Load Tap Changer
OMS	Outage Management System
Opex	Operational Expenditure
OT	Operational Technology
PAHL	Power Asset Holdings Limited
PCC	Porirua City Council
PCS	Power Control System
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
SCPP	Streamlined Customised Price Path
SF6	Sulphur Hexafluoride
SPS	Special Protection Scheme
TASA	Tap Changer Activity Signature Analysis
TCA	Transformer Condition Assessment
TNIFR	Total notifiable injuries per 1,000,000 hours worked
TNO	Transmission Network Operator
UFB	Ultrafast Broadband
URM	Unreinforced Masonry
UHCC	Upper Hutt City Council
VRLA	Valve Regulated Lead Acid Battery
VT	Voltage Transformer
WCC	Wellington City Council
WELL	Wellington Electricity Lines Limited
WeLG	Wellington Lifelines Group
WOM	Work Order Management
W/S	Winter / Summer
XLPE	Cross Linked Polyethylene insulation

Appendix G Single Line Diagram