Wellington Electricity 10 year Asset Management Plan

1 April 2019 - 31 March 2029

Wellington Electricity

10 Year Asset Management Plan

1 April 2019 – 31 March 2029

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

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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 2015).

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.

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Statement from the Chief Executive Officer

Wellington Electricity (WELL) welcomes the opportunity to submit an updated Asset Management Plan (AMP) for the period 2019 to 2029. We confirm that this AMP has been prepared in accordance with the Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012* requirements.

Our operations over the last 12 months have continued to focus on delivering high levels of safety, reliability and service to our customers, while maintaining excellent performance from our network assets.

Health and safety remains a positive driver for improved engagement with our field staff under an outsourced arrangement. During the year we went to market to seek expressions of interest and proposals to renew our field services agreement. We were pleasantly surprised by the competitive bids with negotiations confirming Northpower as faults and maintenance service provider for the next five years. Sharing safety behaviours and standards with sub-contractors has improved safety performance, in particular with Ultra-Fast Broadband (UFB) and street lighting projects throughout the region. However safety is never a destination but a journey of awareness and support for people undertaking their tasks. This is particularly relevant to maintaining wellness through the courage of more engaged conversations.

WELL has continued to work with consumers to understand their requirements and either improve service levels or look to rebalance the cost quality trade off. One critical measure is the two regulated quality targets which are both forecasted to be met in 2018/19. This is a pleasing result of the teamwork involved to avoid an outcome of the last two years of exceeding these quality limits.

Good progress has been made delivering the first year of the three year earthquake readiness programme approved by the Commerce Commission in March 2018. Thirty of the 91 buildings have now been strengthened and most of the emergency underground spare equipment has been procured and stored throughout the region. Stakeholder events are being held to keep our community up to date with the changes.

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. Our key focus is to ensure an efficient spend to deliver a safe and reliable distribution system for consumers. We continue to look for ways to leverage further effectiveness gains from our systems.

The 2019 AMP includes an update on emerging technology and how this is expected to impact the network as consumers adopt new products. One of the aims of the 2019 AMP is to socialise the requirement for the development and implementation of initial new technology investment, such as improving low voltage visibility, through the next five years. This may be used to defer future capacity investment which will be identified in subsequent Asset Management Plans.

Without standards and coordination there is a risk that uncontrolled usage of new technologies will cause an introduction of two way power flows and large changes to traditional demand profiles. This will need to be well managed to maintain supply quality for all consumers. The traditional network response would be to invest in more asset capacity, however new business models are beginning to emerge. A platform approach, with the appropriate tools, would allow visibility of customer technology which could be coordinated to support maintaining the network standards. Retailers would also have opportunities to provide services from their customers to networks. This would maintain the standard of the network system under two way power flows by balancing storage, generation and consumption. Turning the low voltage network into an active grid will require signals and 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 so that new technology investments can be commercialised in support of the network.

Unlocking the benefits of new technology at the low voltage level for customers, retailers and network operators is an important step change in collaboration and co-operation for our sector.

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 from other industrial sources such as gas. Councils are beginning to consider the alternatives and engage with WELL to look ahead for solutions. We have not factored this reinforcement investment into the 2019 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 for consumer purchases in Distributed Energy Resources (DER) hence investment is being targeted at developing better coordination with customers and retailers at the boundaries between the low voltage network and customers supply. The additional investment required is so the network remains capable to deliver on these new demands.

While the regional economy remains stable, low interest rates continue to encourage developers to subdivide land for residential housing as house prices remain strong. Commercially there is a range of projects from new builds, to reinforcement, through to deconstruction resulting from the outturn of the 2016 earthquake event, resulting in a very diverse market.

In response to the Electricity Authority's request for greater cost reflectivity in network tariffs, WELL is looking to build on our existing Electric Vehicle (EV) time of use tariff and roll this out to other consumers as an alternative to building new network capacity for a higher peak demand. The sustainability of charging EV's outside of peak demand periods was a key finding of our EV trial report last year. We expect we will need closer coordination with the motor vehicle industry and new owners so we can meet their expectations on battery charging as well as seek their assistance for flexibility around resolving network peak demand congestion.

The implementation of efficient prices relies on real time interval meter information, consumers to notify distributors of new technology available to the network and an agreed set of standards for how services are traded through consumers, retailers and aggregators to affirm network pricing signals.

WELL is comfortable that expenditure allowances for the forecast period will meet the investment needed for base network requirements. The additional allowances identified are needed to allow new technology to be integrated to enable services from consumers and retailers and to defer capacity investment. Being able to flexibly introduce a service based model incorporating the support of customer DER will ensure we are in the best position to deliver reliable services to customers at a quality which meets everyone's expectations. However, we are at a cross roads where we need to provision the additional allowance if we want to progress.

WELL continues to proactively engage with WorkSafe, the Commerce 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. We continue to provide a safe delivery system that has services and quality levels at price points welcomed by customers.

At the time of writing our 2019 AMP, the Electricity Price Review has continued its consultation process to ask timely questions with regard to consumer affordability and fairness. While social agencies continue to support the most at need cases, it is timely to reflect how we can contribute to fair electricity delivery and affordability. We have teamed up with ERANZ to engage in their project to understand how energy is being consumed in 50 cases where energy poverty could be occurring. This will help us to understand, support and advise what can be implemented to make electricity more affordable to those in critical need. We look forward to providing update on this and similar initiatives in our next AMP.

Being a member of CK Infrastructure Holdings Ltd. 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.

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's (WELL's) approach for the safe, reliable, effective and responsible long-term management of the company's network assets. The AMP explains how electricity supply will be delivered at a quality and price expected by electricity consumers connected to the network.

1.1 Term covered by the AMP

This AMP covers the 10-year period commencing 1 April 2019 through to 31 March 2029. It was approved by WELL's Board of Directors on 28 March 2019.

1.2 Changes from the 2018 AMP

The main changes in this AMP are:

- An update on new technology and how WELL is preparing to manage two way power flows on the network; and
- An update on the works related to the Streamlined Customised Price Path (SCPP) application approved on 31 March 2018.

For further progress on items since the 2018 AMP, an update is provided in Appendix B.

1.3 The Changing Environment

The environment in which WELL operates is changing. The changes include the increased opportunities available from emerging technologies onto the network as consumer needs and technology costs change, the continued resiliency efforts in the Wellington Region to prepare for a major earthquake, WELL's new agreements with its major service partners, the new default price path (DPP) and the effects of the Health and Safety at Work Act 2015 on Business-As-Usual (BAU) activities. These near term changes will impact on WELL's operations going forward and require ongoing revision of investment plans and business models to enable wider benefits. 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 electrification of industrial heat for gas users which will need to be factored into future forecasts but due to the uncertainty are not yet considered here.

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:

1. Digitalisation;
2. Decarbonisation; and
3. Decentralisation.

These changes will have an effect on WELL as new technologies start to gain in their adoption rate with consumers. 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 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 alleviate congestion or maximise capacity availability from Distributed Energy Resources (DER) rather than via traditional larger asset investments.

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. This approach is driven from scenario analysis and presents a prudent and flexible approach to manage uncertainty, while avoiding over build 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 stages. The results of which 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 includes running a collaboration trial within industry participants in 2019 which will help define services that can be valued and traded in order to defer network investment in favour of an efficient DER services model. This is not completely new as hot water load shifting through ripple control has been in place for many years and allows for less network investment and therefore lower costs to consumers. It is taking this approach and applying a digital decentralised model which 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 consumers, prosumers and stakeholders. This investment does however come at a cost which WELL is currently not part of WELL's DPP allowance. It is WELL's opinion that these requested allowances should be incentivised under the Commerce Act 1986, or through application 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 better and lower cost integration;
b) **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;
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 be felt;
e) **Management of distributed resources:** Investigate and trial a platform 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;

[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."*

g) **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

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 risks posed by new technologies may lead to underutilisation of assets for some Electricity Distribution Businesses (EDB's) requiring them to seek accelerated capital recoveries, WELL is of the opinion that this will generally not be the case in the Wellington region. There may be only small portions 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 down. WELL's approach to move towards development of DSO tools, helping provide consumers with a DER platform to manage emerging technologies, will mean that the risk to potential underutilisation of assets will be managed and controlled. By providing consumers with options which could enable dual transfer of energy via a decentralised energy exchange, WELL aims to encourage consumers not to move off-grid.

This is considered a more prudent solution for consumers in the Wellington region rather than applying for accelerated depreciation recoveries as it allows WELL to be an enabler of new technologies for the benefit of consumers that seek to employ them, with retailers and aggregators providing services to assist in maintaining an efficient network system.

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, earthquakes, and equipment failures. 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's SCPP application being supported through a Government Policy Statement to allow Part 4 to address earthquake readiness following the 2016 Kaikoura earthquake. Aside from the resilience improvements associated with WELL's SCPP application[2], an additional positive outcome for Wellington consumers was that, due to a reduction in the Transpower pass through balance, prices remained flat. 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 Figure 1-1 below.

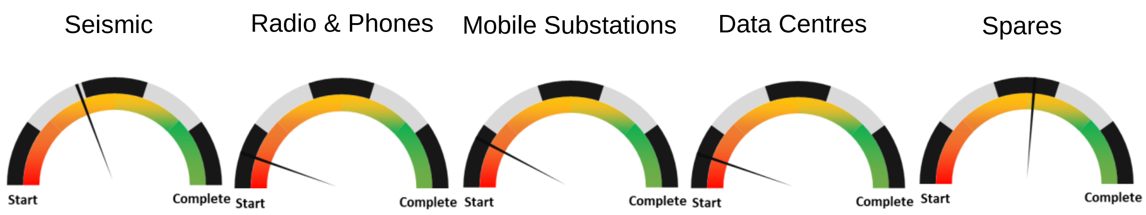


Figure 1-1 SCPP Progress by Work Stream

[2] Full details of all documents related to the WELL SCPP application can be found on the WELL website at: https://welectricity.co.nz/disclosures/customised-price-path/

Continuing in parallel to the SCPP application, WELL has investigated future resilience initiatives with the Wellington Lifelines Group to improve the networks 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
- Whether replacement of high risk 33kV fluid filled cables should be brought forward to speed up restoration following an earthquake.

The expenditure for both items is not included into the forecasts in this AMP as these would need extensive consultation with consumers in the Wellington region prior to implementation because prices will likely increase if these plans were to go ahead.

1.3.3 A New Field Services Agreement

Since 2011, Northpower Ltd has been WELL's primary field service provider responsible for fault response and maintenance. The Field Services Agreement (FSA) with Northpower was renewed in January 2019 following an open-market process run in 2018. In addition, WELL has re-negotiated a new agreement for vegetation management services with Treescape after an open market tendering process.

The new contracts for field services and vegetation management promise to deliver improved services that will be beneficial to consumers and stakeholders.

1.3.4 The Next Price Path

WELL moved from being regulated on a Default Price Path (DPP) to a Customised Price Path (CPP) in March 2018 when the Commerce Commission (the Commission) approved WELL's earthquake readiness expenditure proposal.

The new DPP price path starts on 1 April 2020 and it is expected that WELL will move onto this when the 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. WELL is working with the commission and industry to reset prices and quality for the new DPP.

1.3.5 The Electricity Price Review

The New Zealand government published an Electricity Price Review (EPR) in 2018 for discussion and commentary. The report highlights that since 1990 residential prices in the sector have risen 79%, while commercial prices have fallen by 24%. This was mainly a result of a change in how costs were allocated between residential and commercial customers. Since 1990, a larger proportion of the total shared cost has been allocated to residential customers. Overall, there has been a small increase in distribution prices. The report also highlights that energy is becoming less affordable for lower income families - many households cannot afford the cost of electricity for essential services like heating. In terms of the distribution environment, the report identifies the following factors that may hold back efficiencies:

- Outdated distribution pricing structures;
- Questionable effectiveness of incentives to reduce costs & improve performance;
- The small size of some distributors;
- Access to meter data;
- Quality of governance;
- Ageing assets; and

- Short planning horizons.

As discussed in Section 5, one of the outcomes from the EPR has been an industry-wide focus on energy hardship as one of their key recommendations. To this effect WELL is partnering with Electricity Retailers' Association of New Zealand (ERANZ) to implement a pilot programme, currently titled 'EnergyMate'. The Wellington portion of the EnergyMate programme will target customers in the suburb of Porirua with a personalised visit aimed at developing a plan for managing their energy use; improving the energy efficiency of their homes and connecting them with agencies who can provide financial support. This programme will help WELL to develop communication tools which can be used by low income customers to increase their understanding of how they can more easily afford energy use. Families will have a much better understanding of how to spend their electricity dollar wisely. The aim is to ensure that families can afford to maintain warm and healthy homes. The pilot programme will be reviewed upon completion before any further rollout.

WELL continues to take action to address concerns raised in the EPR. The AMP outlines the following items which will improve electricity distribution services for residential consumers:

- WELL's pricing roadmap;
- WELL's initiatives with ERANZ to learn and advise on energy efficiency as part of the EnergyMate initiative;
- Development of a Smart Power Portal to provide consumers with better information;
- WELL's initiatives to improve network performance and the associated cost of these initiatives;
- WELL's emerging technology roadmap and the usage of behind the meter data;
- WELL's thought leadership in changing business models to socialise customer DER to support deferment of network investment, lowering long term costs to consumers;
- WELL's governance structures; and
- WELL's assets management framework and resultant investment plans.

1.3.6 The 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, and that risk is considered and controls adopted so that health and safety is well managed in the workplace. WELL supports the ongoing commitment to continual improvement and 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 EDB's, 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 compared to the reference period. WELL response in 2018 is to maintain reliability levels by deploying portable generations. These effects and WELL's use of generators are further discussed in Section 6.

1.4 Trend in Energy Consumption

Since 2011, annual energy consumption in the Wellington region has fallen by an average rate of 1% per annum but with a slight upturn in 2018/19. Actual consumption on the network will be driven by seasonal temperature variations and the associated consumer responses, an uptake of emerging technologies, and the timing of large-scale one-off consumer-led developments. WELL has a winter peaking network, and a colder than usual winter or a higher uptake of EVs would both drive an increase in energy demand and consumption. Changes in consumption patterns can also depend on clear pricing signals to enable consumers to make informed decisions. Both The Electricity Authority and the EPR highlighted the importance of clear pricing signals to manage congestion and to allow consumer to make informed energy choices when they consider emerging technology.

1.5 Service Levels

WELL continues to deliver services to consumers 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, four areas of service level measures have been established for the period covered by the AMP. These are:

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

1.5.1 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 Work Safe New Zealand legislation (HSW Act 2015) 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 operating:

- 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:

- Report on at least 300 near misses per annum;
- Maintain contractor engagement through site visit assessments at 600 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 2019 focus will be placed on the following areas to further improve performance:

- Reinforcement of WELL's new 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;

- Review 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 consultation, coordination and cooperation where work involves overlapping Person Conducting a Business or Undertaking (PCBU) duties; and
- Increase strategic risk collaboration with contracted field service providers in development of practical and effective risk controls.

1.5.2 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 has used the insights received from customer engagement to test the service levels provided and to inform investment plans for the planning period.

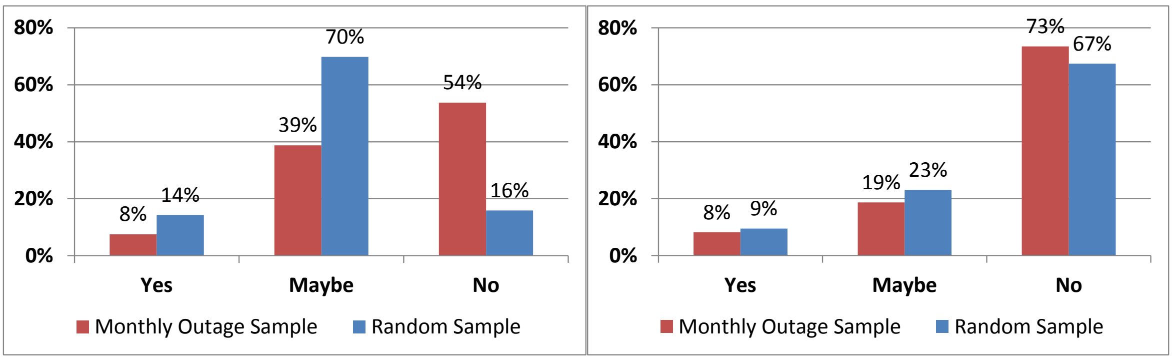
In addition to good reliability and appropriate prices, customers increasingly expect accurate and timely information on their service and its status. Most customers accept occasional power cuts and the ability to keep them informed as to when supply will be restored is also important. Ensuring good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

1.5.2.1 Customer Engagement

WELL engages with customers via the various initiatives it undertakes, such as the electric vehicle (EV) charging trial undertaken in 2018. There is also collaborative work being undertaken in a similar technology space with a retailer trialling the use of domestic photovoltaics (PVs) and batteries within the region.

Larger consumers 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.

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 2018 are shown in Figure 1-2.



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 1-2 Sample of 2018 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 "Outage Check" 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 is looking at establishing 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 is expected to be delivered in 2019. These improved connections and self-service tools being developed for the website may be partnered by a project to establish service level expectations for quote requests, dependent on the complexity of work types.

WELL has two customer related performance measures. These are:

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

1.5.2.2 Power Restoration Service Level Targets

WELL's published 'Electricity Network Pricing Schedule' provides standard service levels for the restoration of power to two different categories of consumers: Urban and Rural. These service levels reflect previous feedback from WELL consumers and are agreed between WELL and all retailers. The targets for power restoration service levels remain consistent over the planning period 2019-2029 and are shown in Table 1-1.

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Table 1-1 Standard Power Restoration Service Level Targets 2019-2029

1.5.2.3 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 1-2.

	Service Element	Measure	Target 2019 to 2029
A1	Overall service level	Average service level across all categories	>80%
A2	Call response	Average wait time across all categories	<20 seconds

	Service Element	Measure	Target 2019 to 2029
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 1-2 Contact Centre Service Level Targets 2019-2029

1.5.3 Reliability Performance

Wellington's electricity network, although strong due to its underground cabling, can be vulnerable to damage from external events. 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 this reason, WELL is committed to providing customers with a reliable and secure electricity supply. WELL has consistently demonstrated this commitment by undertaking reliability improvement initiatives to further progress the performance of the network, some of which are highlighted below:

- The worst performing feeder improvement programme such as work undertaken to improve the quality of supply experienced for customers in the Whiteman's Valley supplied by the Maidstone 10 11 kV feeder ;
- Analysis of incidents and outages to identify continual improvement opportunities. In 2018 this included, for example, a greater use of portable generators to reduce the impact to consumers of planned outages; and
- Work undertaken based on 2017/18 reliability performance to improve practices in vegetation management as well as greater engagement with tree owners which has resulted in markedly improved vegetation management 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 2019/20. The caps and collars are set using historical data at one standard deviation above and below the mean (target). The caps and collars are the maximum and minimum reliability outcomes for which a reward or penalty of $101,268[3] per SAIDI minute and $6,718,135 per SAIFI unit apply if the company's performance is better

[3] The rewards and penalties relate to WELL only and are calculated on an EDB by EDB basis.

than or below the target respectively. In addition, the Commission has retained a compliance test for reliability which is based on meeting the limit in the current year or both of the immediately preceding two years. The target and limit for WELL up to 2021 are presented in Table 1-3.

Regulatory Period 2016-2020	Annual SAIDI	Annual SAIFI
Target	35.44	0.547
Limit	40.63	0.625

Table 1-3 WELL Annual Regulatory Reliability Targets and Limits

The SAIDI and SAIFI targets against the historical performance are shown in Figures 1-3 and 1-4. The 2018/19 year includes a forecast to account for the March 2019 month shown in dark blue.

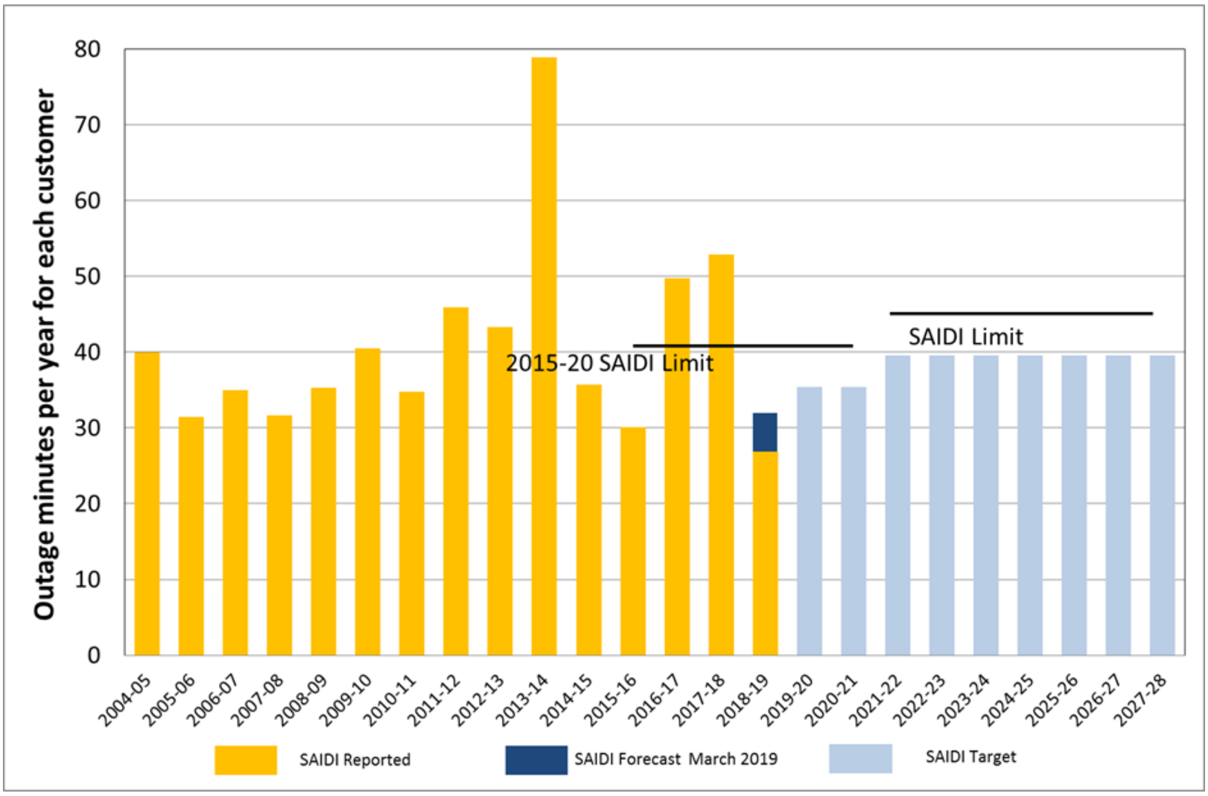


Figure 1-3 WELL SAIDI Performance

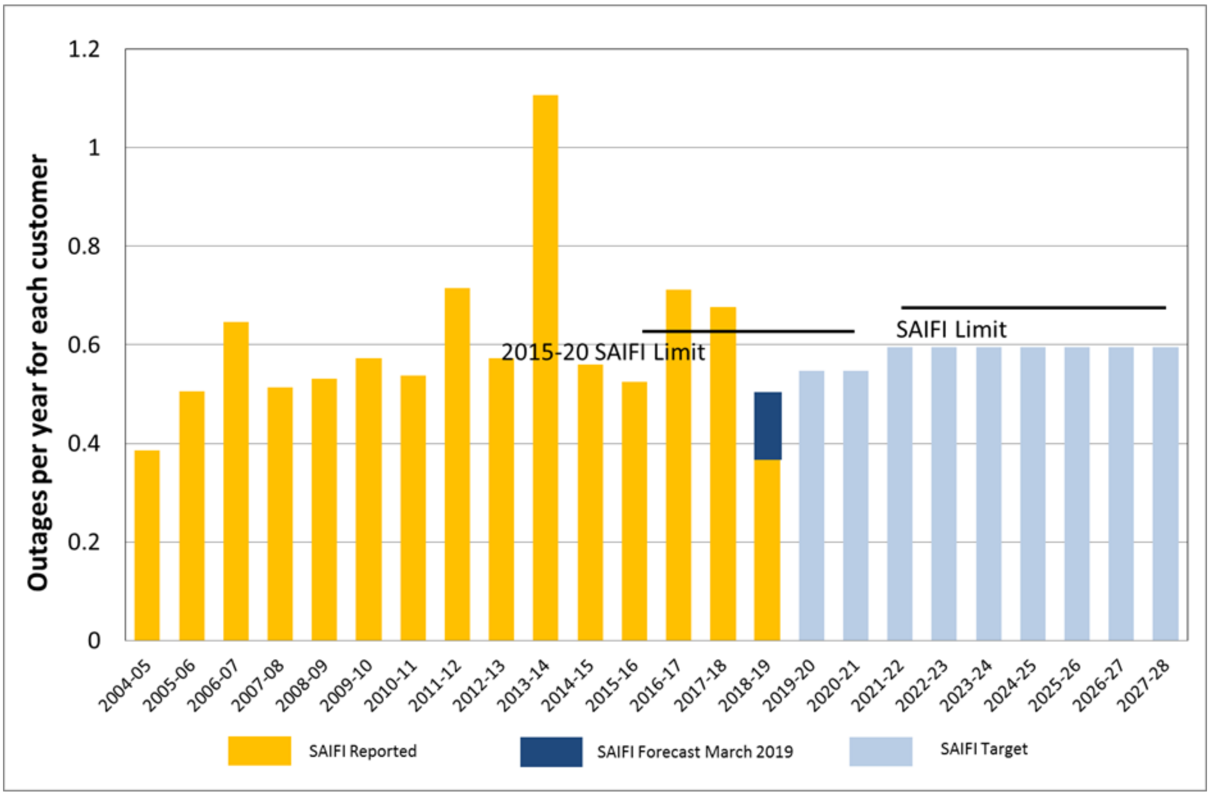


Figure 1-4 WELL SAIFI Performance.

The primary drivers for network performance in the 2018/19 regulatory year have been a continued increase in the number of faults due to third party vehicle contacts and an increase in the amount of de-energised work being undertaken. The performance of the overhead network year to date has been better than average, in part reflecting the benefit of the actions implemented following the Strata review of 2015/16 as well as other continual improvement initiatives.

Analysis of the main causes of the network performance and WELL's initiatives to respond in future years is provided in Section 6.

1.5.4 Asset Efficiency

The asset efficiency levels of WELL relate to the effectiveness of its fixed distribution assets[4].

Table 1-4 illustrates the levels of asset efficiency.

	Load factor %	Distribution transformer capacity utilisation %	Loss ratio %	Demand density kW/km	Volume density MWh/km	Connection point density ICP/km	Energy density kWh/ICP
Industry average	59.0	30.15	5.6	40.3	185.5	12.3	15,956
WELL	47.5	39.51	4.7	122.8	486.2	35.3	13,761
Levels 2019-2029	>50	>40%	<5	-	-	-	-

Table 1-4 WELL Asset Efficiency Levels to 2029

[4] Values taken from the Pricewaterhouse Coopers (PwC) Electricity Line Business 2018 Information Disclosure Compendium.

1.6 Network Expenditure

WELL's investment profile for the period through to 2021 is consistent with the expenditure allowances inclusive of the SCPP. Beyond 2021 there is a shift expected in terms of expenditure allowances in order for WELL to maintain an appropriate level of service while addressing the emergence of new technologies such as Electric Vehicle and Distributed Generation (as indicated in Section 9). This is dependent on current assumptions including expected peak demand profiles. A short overview of the demand forecast is provided below followed by the expenditure forecasts.

1.6.1 Demand Forecast

The consumption of energy supplied through the network has declined at an average rate of 1% per annum from 2011 to 2018 with a slight upturn in 2019. The decline was attributed to energy efficiency improvements. Whilst energy consumption is on the decline, maximum demand is on the increase. This is important to note, as it is demand that drives network investment and energy drives technology investment. 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 northern belt. Figure 1-5 shows the number of building consents issued for new houses and apartments over the last seven years, however this is expected to stabilise over time.

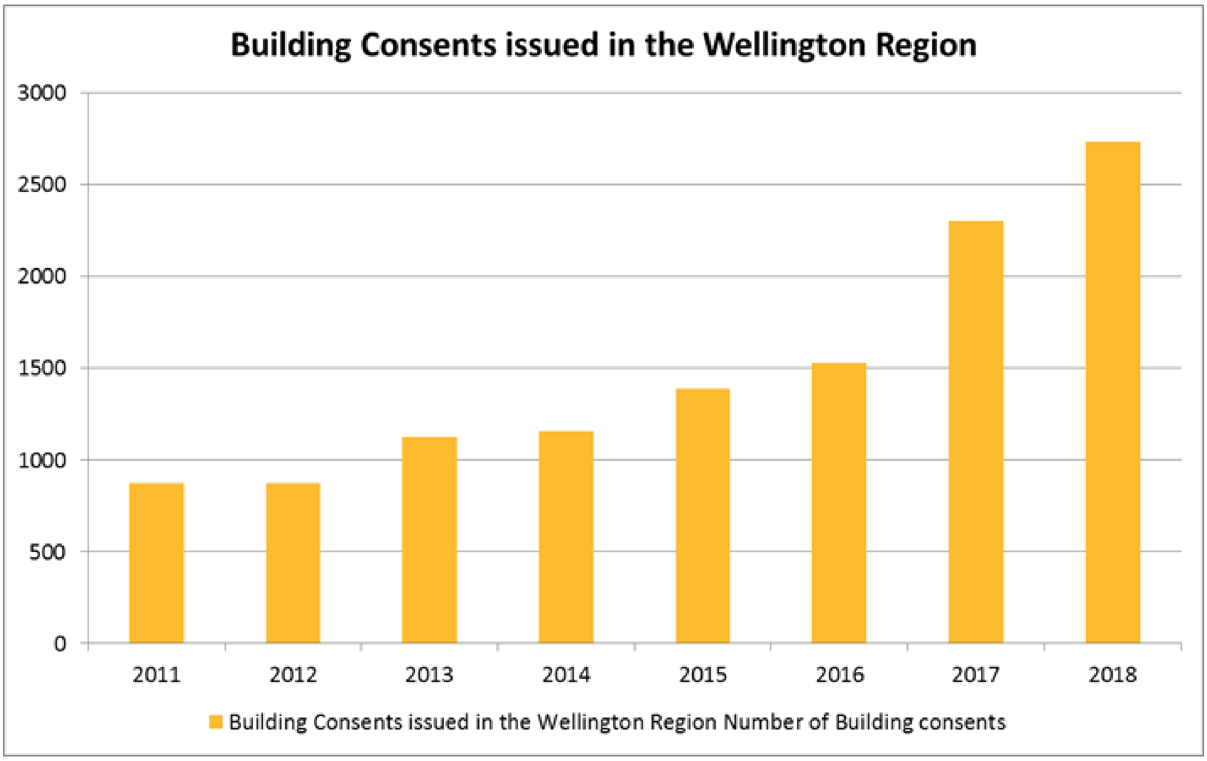


Figure 1- 5 Number of Building Consents Issued in the Wellington Region

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.

Despite the overall decline in energy use, the sustained peak demand is forecast to grow in some localised areas of the network, driven by new commercial and residential developments. This reflects a decoupling between the overall volume of energy consumed and the peak demand. There is also a strong correlation between peak demand and climatic conditions. Generally, demand peaks within the Wellington region are driven by winter temperatures on the coldest days.

While the overall 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.

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

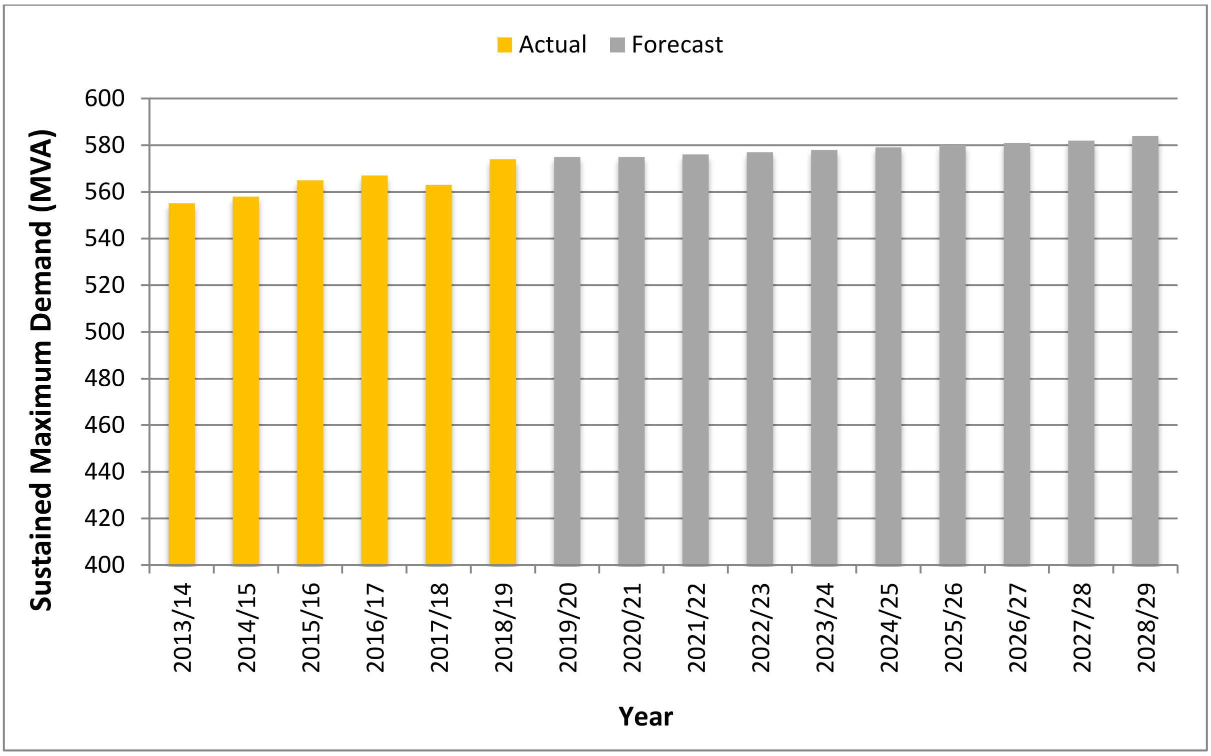


Figure 1- 6 Network Historic and Forecast Demand

With the change in pricing methodology to adopt cost-reflective pricing where price periods signal more clearly peak demand reduction, new technology investments are more likely to augment the network ahead of the traditional investments.

The evolution of technology supported by different pricing plans and business models will incentivise consumer 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.

1.6.2 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 the largest component of the forecast and is driven largely by the replacement of a high quantity of assets such as poles, switchgear and 11 kV/400 kV substations.

2. Regulatory, 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 (including the data centres[5]).

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.[6]

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 forecast is shown in Figure 1-7[7].

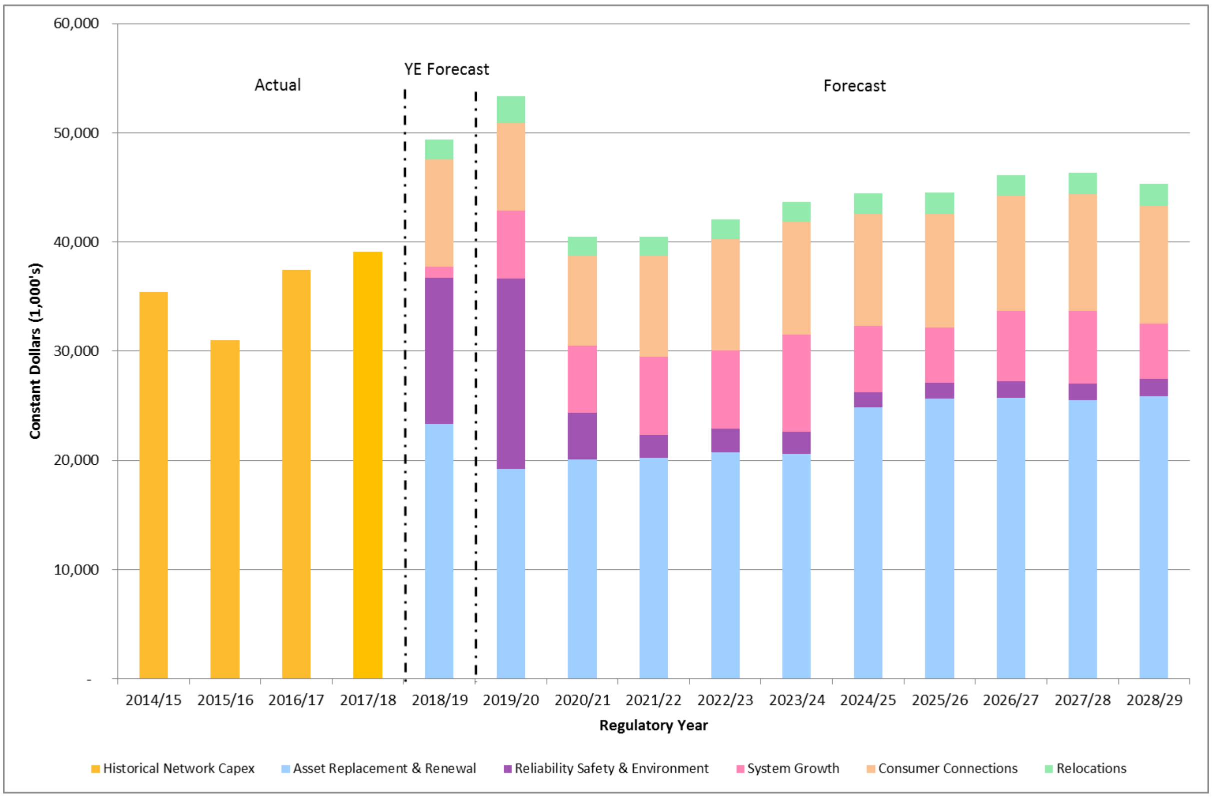


Figure 1- 7 Network Capital Expenditure Forecast

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. Forecast expenditure on running trials to develop emerging technologies is included in the System Growth category which is discussed in Section 9.

[5] For purposes of clarity, the non-network SCPP expenditure for the data centres have been included into the Regulatory, Safety and Environment category in this chart, but this has been separated out in the rest of the document and the Capex schedules.

[7] The remaining SCPP expenditure has been included into the Reliability, Safety and Environment Category above and in the Capex schedules.

[6] 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.

1.6.3 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.
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 forecast is shown in Figure 1-8.

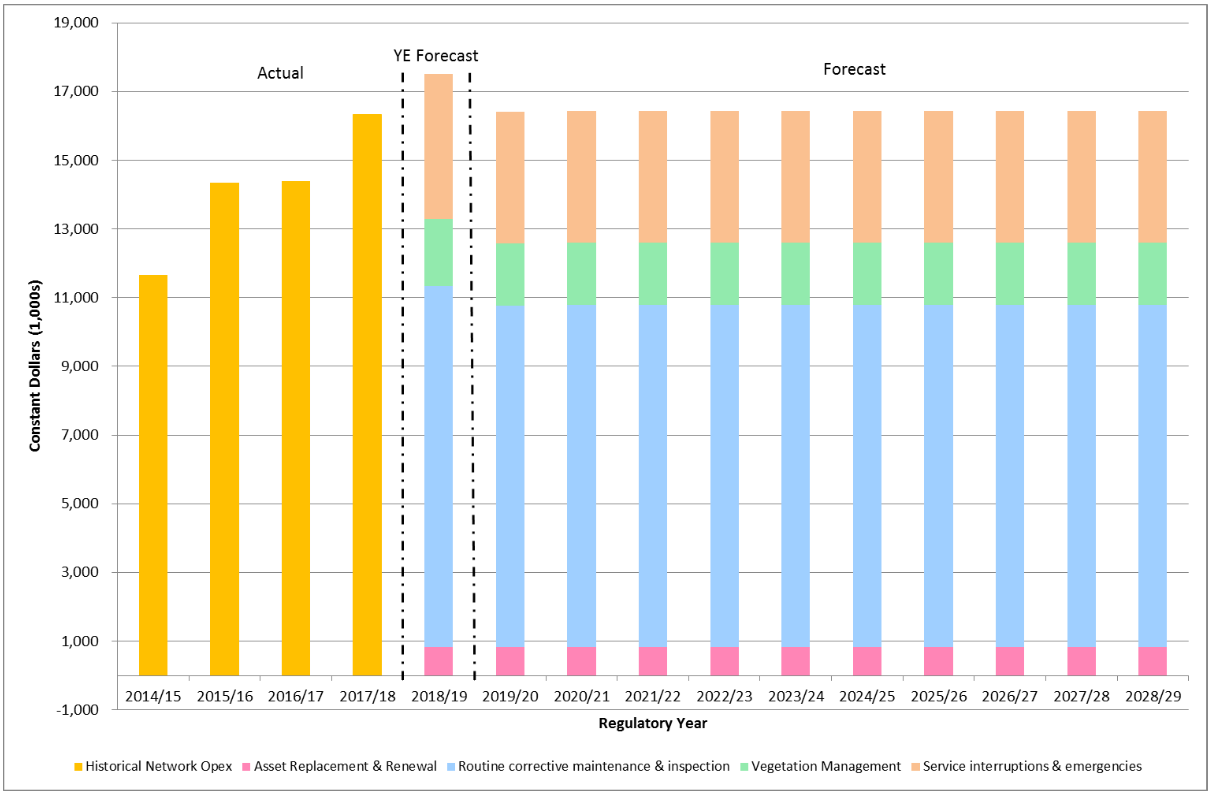


Figure 1- 8 Network Operational Expenditure Forecast

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 CK Infrastructure Holdings Ltd. 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.

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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 2019 to 31 March 2029.

The document was approved for disclosure by the WELL Board of Directors on 28 March 2019.

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".*

The asset management practices and 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;
- **Targets and Levels of Service** which provides an overview of the various safety, customer and reliability targets that WELL is measured against and the achieved performance against those service levels; 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.

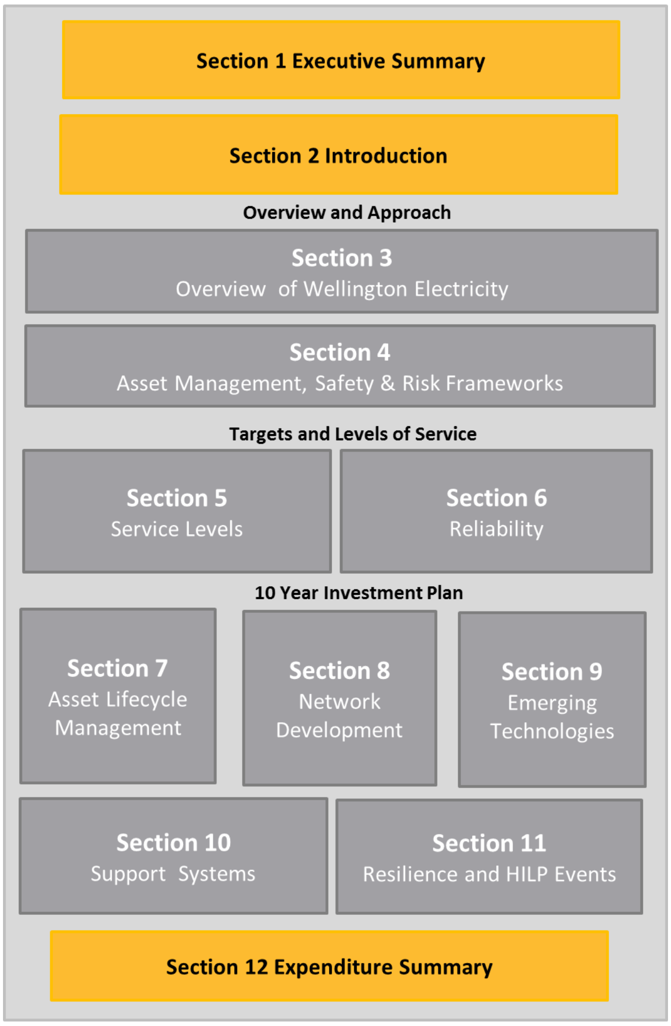

Figure 2-1 Structure of the 2019 AMP

2.3 Formats used in this AMP

The following formats are adopted in this AMP:

- Calendar years are referenced as the year e.g. 2019. 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. 2019/20;
- All asset data expressed in figures, tables, and graphs is at 31 October 2018 unless otherwise stated;
- ICP numbers are as at February 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, investment projections 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 as part of the DPP allowances, also include the expenditure approved under the SCPP to improve WELL's earthquake readiness. These 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. Expenditure related to the long term resilience of the network has not been included as part of these projections due to the current regulatory mechanism being unable to support such expenditure. This will require significant customer engagement to review the price quality trade-offs.

The forecasts related to new technology 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 from gas fuel sources. This investment has not been factored into this plan as forecasts for reduced gas availability 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. Financial values presented in this AMP are in constant price 2019 New Zealand dollars, except where otherwise stated.

Section 3

Overview

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 as well as 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, and will be used to inform its 2019 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.

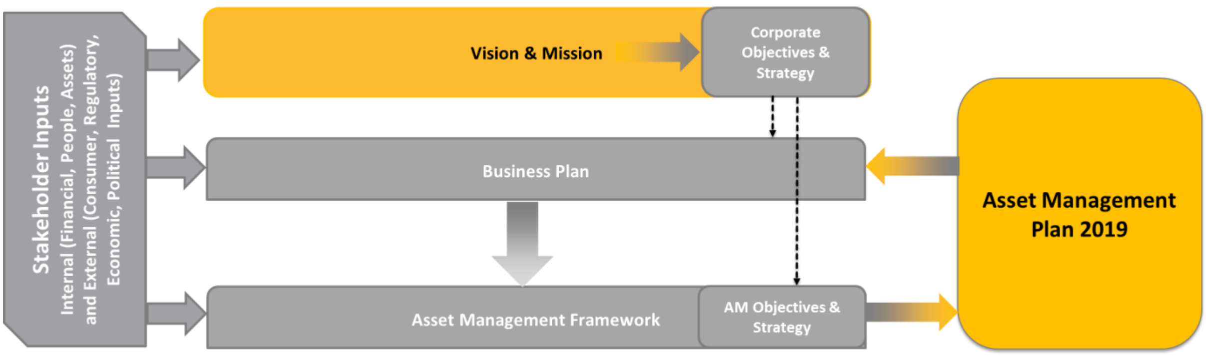

Figure 3-1 Interrelationship between WELL's Mission, the Business Plan, the Asset Management Framework and the AMP

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 Ltd. together own 100 per cent of WELL. Both shareholding companies are members of the CK Infrastructure Holdings Ltd. group of companies, which are listed on the Hong Kong Stock Exchange.

The CK Infrastructure Holdings Ltd. 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[8]) 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 against budget, and reliability statistics 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 Ltd. 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 also 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.

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

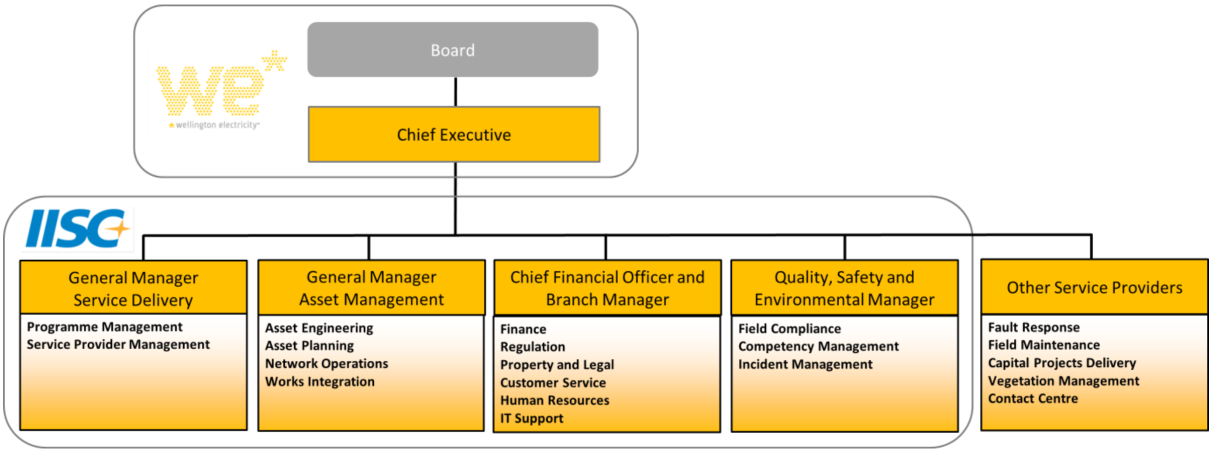

Figure 3-2 WELL Organisation Structure

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[9].

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 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 project management of capital and maintenance works and the associated safety, quality and environmental performance of these works. Responsibilities also include the management of outsourced field services contracts.

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

[9] 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 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 two areas: management of delivery of capital and maintenance works on the network, and management of the specialist contracts. The responsibilities for each area are described in Table 3-2.

Service Delivery Team	Asset Management Responsibilities
Capital Works and Maintenance programme management	• Overview of the capital works plan and maintenance delivery • Programme management of field service activities • Supporting customer requests • Project management of contestable works • Safety frameworks for project implementation
Contract Management	• Management of specialist contracts – Field Services Agreement, Vegetation Management, Chorus agreement, • Safety performance and corrective actions • Relationship management with stakeholders

Table 3-2 Service Delivery Responsibilities

3.2.5.3 Commercial & 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 • Ensure that identified risks are adequately catered for
Finance	• Adequate funding of asset management plans

Table 3-3 Commercial & Finance 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 Responsibilities

WELL outsources the majority of its field services tasks as well as its 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 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

- 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 168,000 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 in many cases 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 split further into the Northwest and Northeast areas to reflect the natural geographical and electrical split between the areas.

Figure 3-3 shows the network split into these three areas for planning purposes: Southern, defined as the area supplied by Wilton, Central Park and Kaiwharawhara Grid Exit Points (GXPs); Northwestern, defined as the area supplied by Takapu Road and Pauatahanui GXPs; and Northeastern, defined as the area supplied by Upper Hutt, Haywards, Melling and Gracefield GXPs. The network configuration for each of the three areas is described further in Section 3.4.

Figure 3-3 WELL Network Area

3.4 The Network

The total system length of WELL's network (excluding streetlight circuits) is 4,549 km, 63% 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 sub transmission system distributes the supply from the Transpower GXPs to 27 zone substations at N-1[10] security level. The 33 kV system is radial with each circuit supplying its own dedicated power transformer, with the exception of Tawa and Kenepuru where two circuits from Takapu Road are tee-ed to supply four transformers (two at each substation). All 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 sub transmission network is included in Appendix F[11].

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.

[10] 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.

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

The zone substations in turn supply the 11 kV distribution system which distributes electricity directly to the larger consumers and to 4,370 distribution substations located in commercial buildings, industrial sites, kiosks, berm-side and on overhead poles. The total length of the 11 kV system is approximately 1,773 km, of which 67% is underground. 71% of the 11 kV feeders in the Wellington CBD[12] 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 2,776 km, of which 61% is underground. An additional 1,915 km of LV lines and cables are dedicated to providing street lighting services.

Each of WELL's three network areas is 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 sub transmission network configuration.

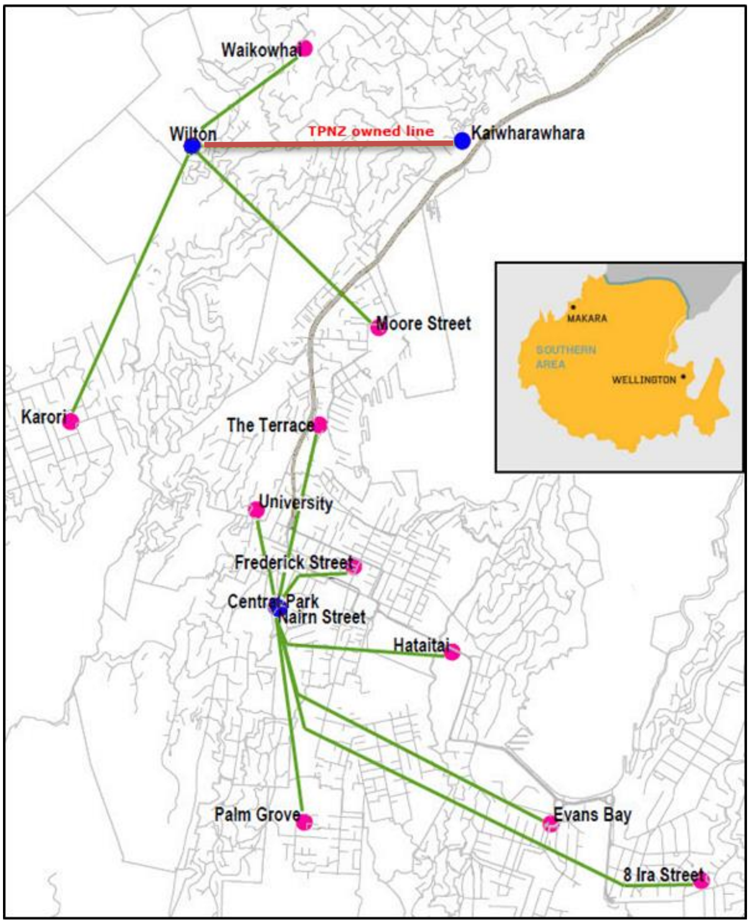

Figure 3-4 Wellington Southern Area Sub-Transmission Network

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

3.4.1.1 Central Park (48,916 ICPs)

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 (12,329 ICPs)

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 (5,889 ICPs)

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 – 2018 (MVA)	Firm Capacity[13] (MVA)	Volumes – 2018 (GWH)	ICP Count[14]
Central Park 33 kV	33	149	228	690	42,041
Central Park 11 kV	11	23	30	98	6,875
Wilton 33 kV	33	43	106	167[15]	12,329
Kaiwharawhara 11 kV	11	29	41	148	5,889
Total				**1,105**	**67,134**

Table 3-5 Summary of Southern Area GXPs

[13] Firm Capacity is the N-1 transformer capacity.
[14] This includes active & disconnected ICP's
[15] This includes 185 GWh injected by Mill Creek Generation

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 sub transmission network configuration.

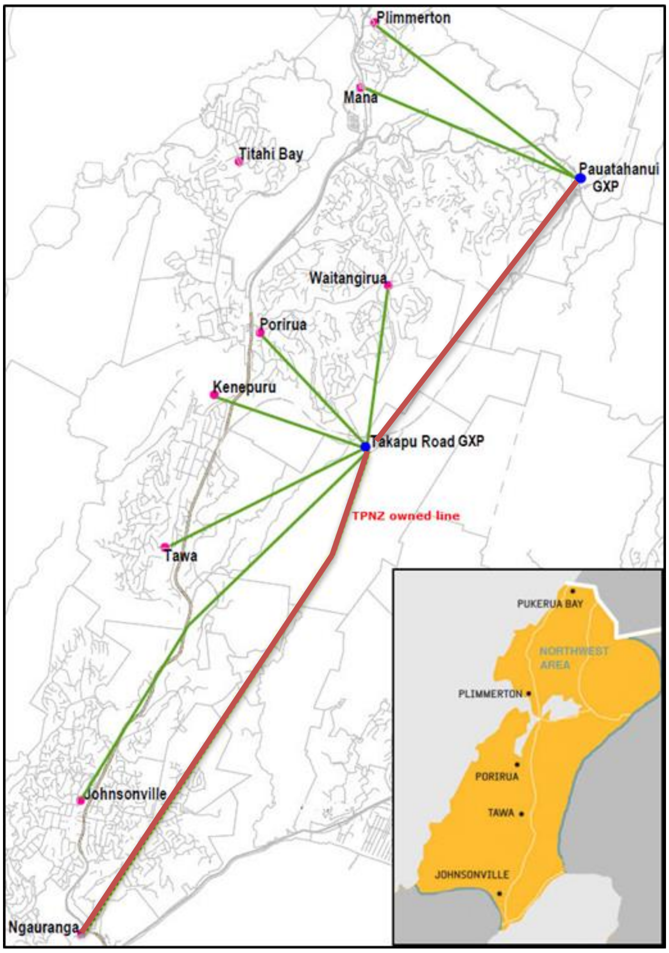

Figure 3-5 Wellington Northwestern Area Sub transmission Network

3.4.2.1 Pauatahanui (6,727 ICPs)

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 (32,659 ICPs)

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 – 2018(MVA)	Firm Capacity (MVA)	Volumes – 2018 (GWH)	ICP Count[16]
Pauatahanui 33 kV	33	18	24	71	6,727
Takapu Rd 33 kV	33	91	123	401	32,659
Total				**472**	**39,386**

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 sub transmission network configuration.

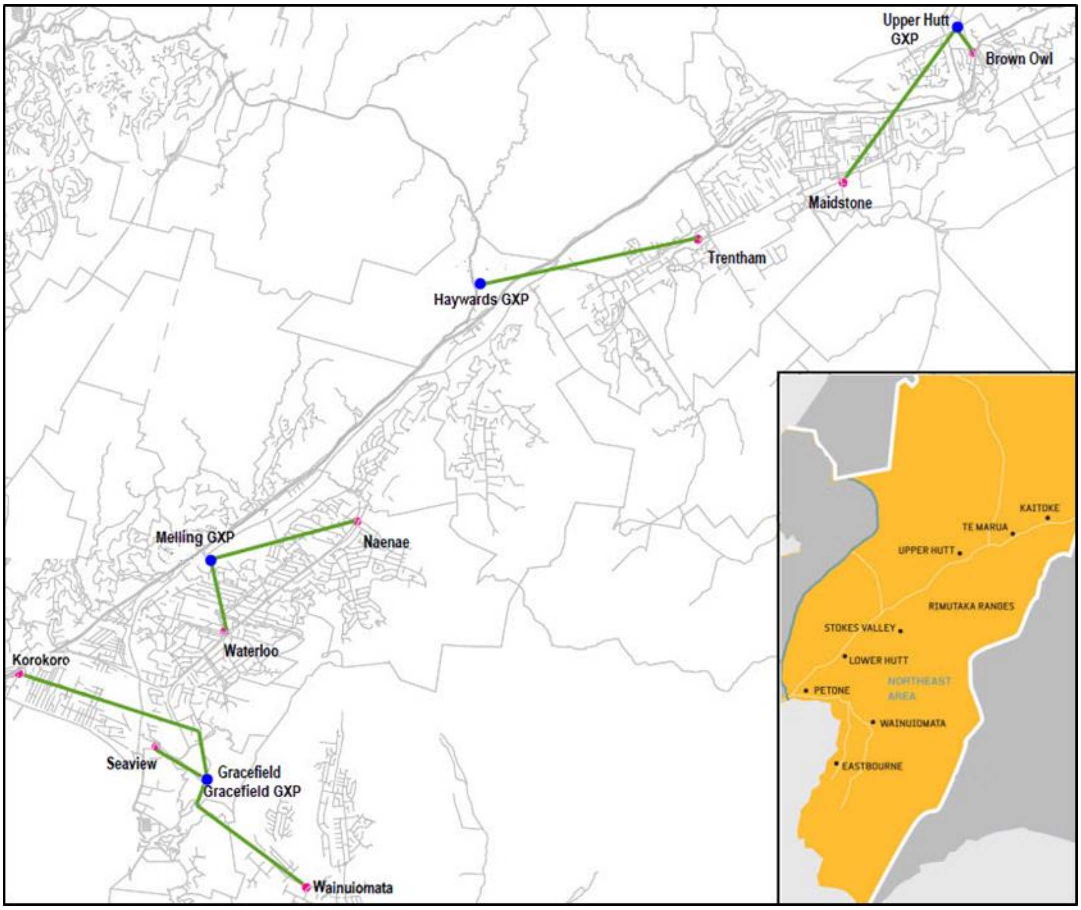

Figure 3-6 Wellington Northeastern Area Sub-Transmission Network

[16] This includes active & disconnected ICP's

3.4.3.1 Upper Hutt (11,088 ICPs)

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.

3.4.3.2 Haywards (11,964 ICPs)

Transpower's Haywards GXP has a single 110/11 kV transformer nominally rated at 20 MVA and a single 110/33 kV transformer nominally rated at 20 MVA. A 5 MVA 33/11 kV transformer links the 33 kV and 11 kV switchboards. WELL takes supply to two 33 kV circuits that supply Trentham zone substation, and eight 11 kV feeders. Haywards is the only GXP that does not currently offer full N-1 security to WELL's connected assets. A project is underway with Transpower to replace the supply transformers with three winding transformers to provide N-1 security in 2019. Security is currently provided by backfeeds in the WELL 11 kV network.

3.4.3.3 Melling (19,777 ICPs)

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 (18,755 ICPs)

Transpower's Gracefield GXP comprises two parallel 110/33 kV transformers nominally rated at 85 MVA each supplying their 33 kV indoor bus. 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 – 2018 (MVA)	Firm Capacity (MVA)	Volumes – 2018 (GWH)	ICP Count[17]
Gracefield 33 kV	33	60	89	277	18,755
Haywards 33 kV	33	14	20	68	5,234
Melling 33 kV	33	33	52	136	12,712
Upper Hutt 33 kV	33	30	37	128	11,088
Haywards 11 kV	11	14	20	68	6,730
Melling 11 kV	11	25	27	115	7,065
Total				**778**	**61,584**

Table 3-7 Summary of Northeastern Area GXPs

3.4.4 Embedded Generation

There is a wide range of embedded generation connected to the network, including 969 installations of PV with 3,141 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. Future planning is important to ensure that WELL is in a position to react to future challenges such as changes in emerging technologies.

3.5 Regional Demand and Consumer Mix

In 2018/19 WELL's network is forecast to deliver 2,525 GWh to consumers around the region where the regional sustained maximum demand was 531 MW. As illustrated in Figure 3-7, the volume of energy supplied through the network has declined at an average rate of 1% per annum from 2011 to 2019.

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[17] This includes active and disconnected ICPs

This past year has seen a trend of increased volumes even though the overall the trend shows that energy volumes are on the decline. The sustained maximum demand is showing a trend of increase in the past 6 years; this is important to note as the need for network investment is driven by demand.

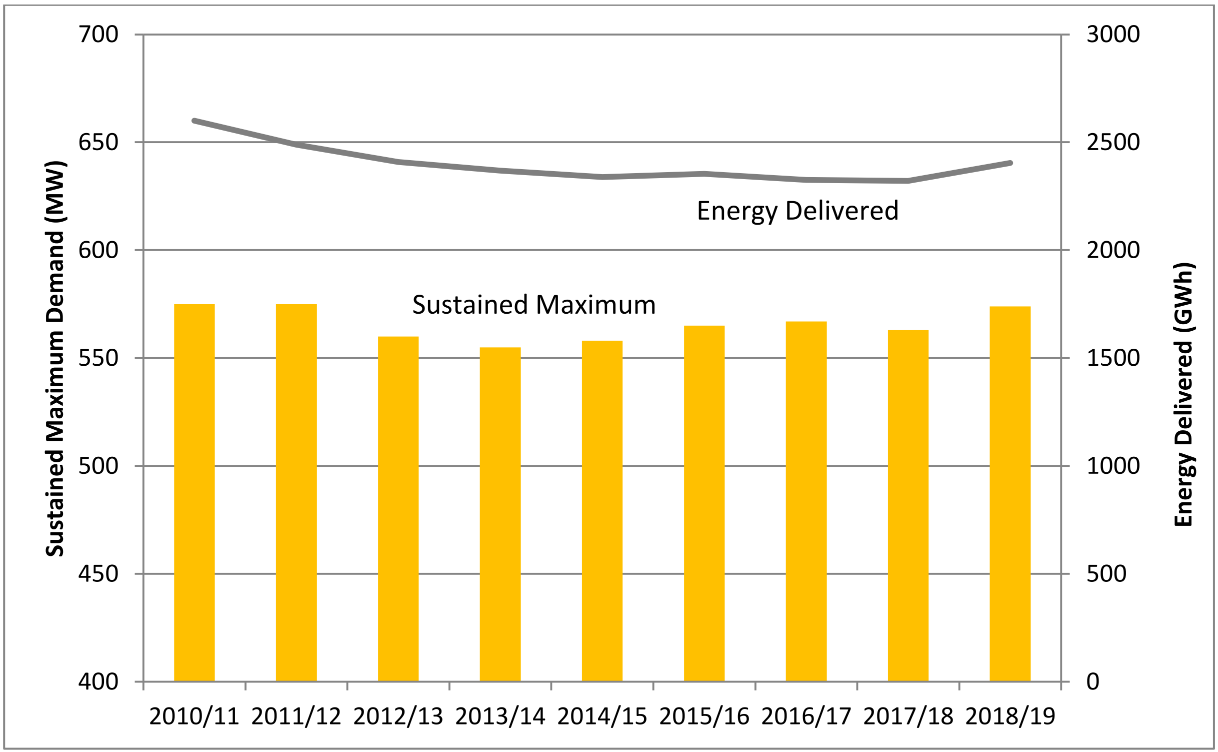


Figure 3-7 Maximum Demand and Energy Injected

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

Consumer Type	ICP Count[18]
Residential	150,726
Large Commercial	451
Medium Commercial	630
Small Commercial	15,037
Large Industrial	53
Small Industrial	262
Unmetered	841
Total	**168,000**

Table 3-8 WELL's Consumer Mix as at February 2019

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

[18] This is only active ICP's

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

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 largest consumers are:

- Hutt City Council
- Wellington City Council
- Kiwirail
- Wellington Hospital
- Chorus
- Foodstuffs
- Greater Wellington Regional Council
- Weta digital group
- Victoria University
- Porirua City Council
- Parliamentary Services
- TePapa
- Hutt Hospital
- Westpac Stadium
- Ministry of Justice
- The Warehouse Limited
- NZTA
- Vodafone
- Progressive Enterprises

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 with the EV trial project undertaken in 2018. The 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 was undertaken in 2018 to improve the customer experience by improving the accuracy of published estimated times of restoration.

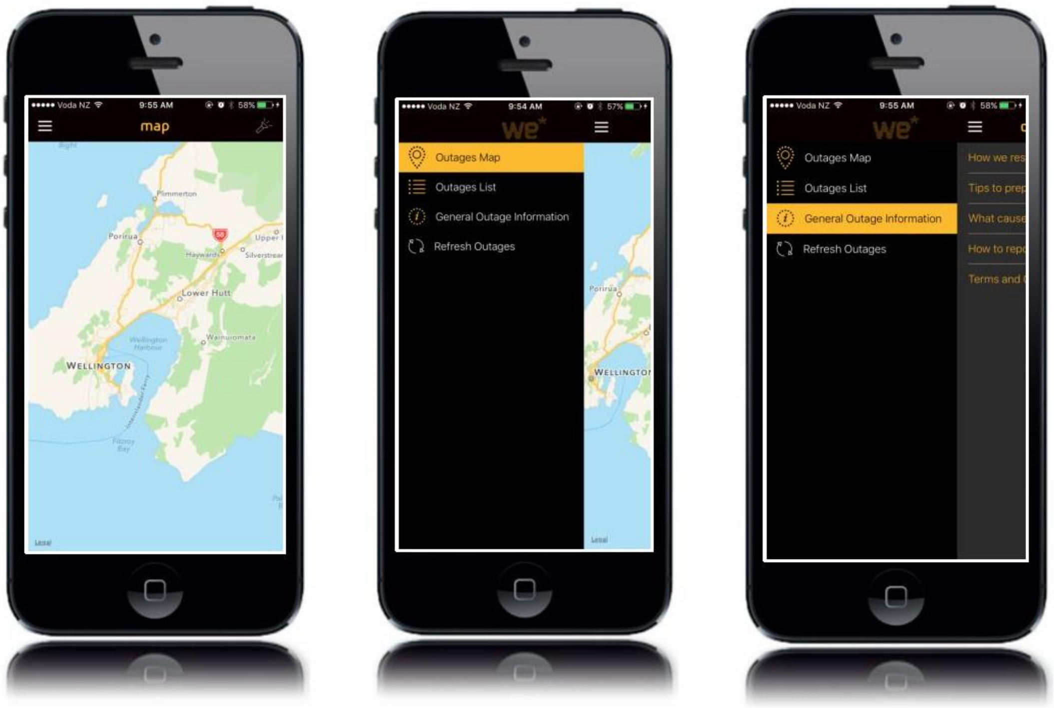


Figure 3-8 WELL's Web-based Application

WELL is establishing 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 is expected to be 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 by 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 a recent visit to residents of a street in Kingston impacted by a prolonged outage, and (WELL initiated) discussions with community associations in the 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 plans to work with the Authority and other market participants on a revised Use of System Agreement (UoSA) but is awaiting the outcome of an appeal court judgment on the Authority's right to introduce a Default Distributor Agreement (DDA) before embarking on that programme.

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 is also currently undertaking collaborative work 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 (PCBU's). 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.

The differences between Transpower's transmission charges and WELL's distribution charges for a residential customer per year are shown in Figure 3-9.

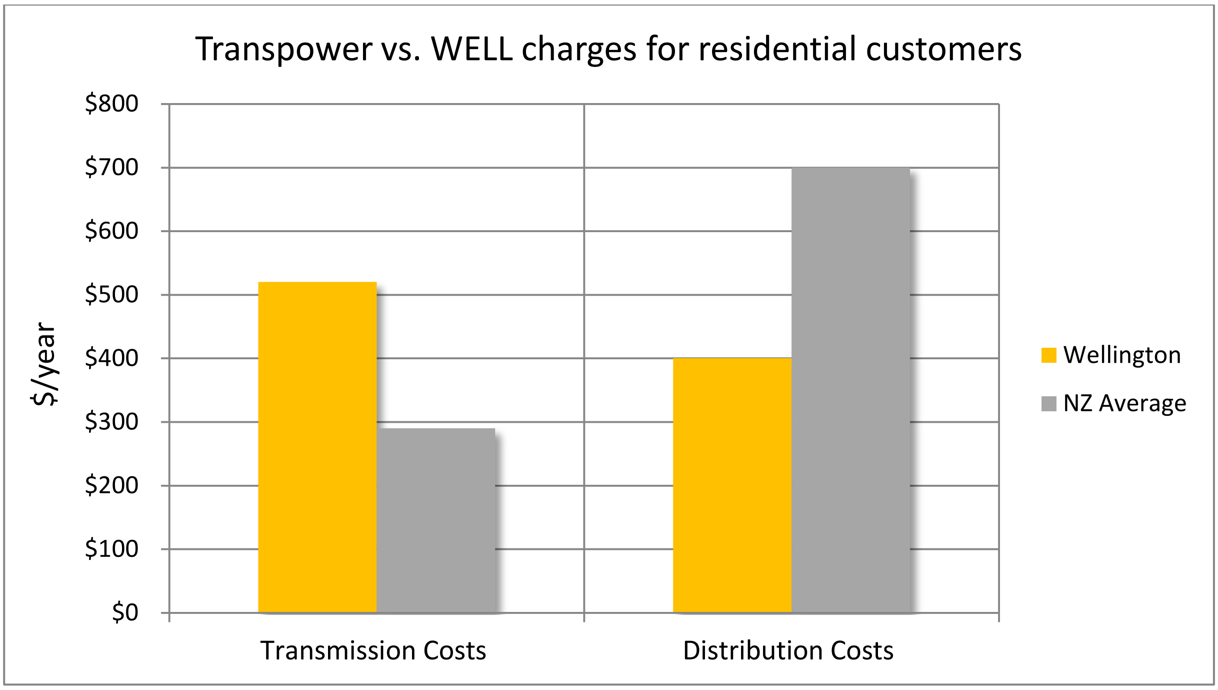


Figure 3-9 Comparison of Transmission and Distribution Charges for Residential Customers[19]

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.

[19] Source: Electricity Price Review

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, submissions 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 01 April 2018, WELL has been on a revenue cap due to the approved SCPP application, which will run until 31 March 2021. As part of the approved SCPP, 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.

3.7.1.3 Information Disclosure

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

3.7.1.4 Model Use of System Agreement (MUoSA)

Since 2012 the Authority has continued to indicate that at some point it would consider mandating a model or default agreement through regulation. This approach by the Authority has tended to hinder any negotiations with retailers as they have sought to wait until the Authority regulated the agreements.

The Authority's work to introduce a DDA to set the terms in which retailers and EDBs contract for the supply distribution services is ongoing.

3.7.1.5 Pricing Roadmap

WELL has published a pricing roadmap that outlines the intended developments in distribution pricing over the next 3-5 years including the development of cost reflective pricing options to provide retailers and consumers with clear price signals to help reduce peak demand.

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 UFB rollout is nearing its end but it is expected that there will be an increase in the requests for provisioning due to the Rugby World Cup in 2019.

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 have impacts on the 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. A review of the Tree Regulations is expected to occur in 2020.

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 retail, as well as at consumer level with markets developing to deliver choices for homes and businesses.

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), 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 of course significant uncertainty with some technology increasing energy transferred (e.g. EVs), while others will reduce energy transferred (e.g. PV).

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

i) **New technology standards:** Introduce new standards for new technology, allowing better and lower cost integration;

j) **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;

k) **Congestion standards**: Introduce standards on how congestion is defined and require network congestion to be disclosed;

l) **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;

m) **Management of distributed resources:** Investigate and trial a platform that enables the management of distributed energy resources;

n) **Support with efficient prices:** Introduce efficient prices that reflect the benefits and encourage the use of disruptive technology;

o) **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

p) **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. This approach is driven from scenario analysis and presents a prudent and flexible approach to manage uncertainty, while avoiding over build in the short term. It is WELL's view that new systems which enable LV monitoring capability and working closely with other industry participants will deliver the best long term solution for New Zealand.

As new technologies become available and gain more penetration with consumers, WELL seeks to utilise its position as part of CK Infrastructure Holdings Ltd. to leverage new technology from other global players, to provide network alternatives to consumers. These options can then be made available for consideration for use in network development plans and asset renewals. CK Infrastructure Holdings Ltd. has established a global presence with investments in the electrical sectors throughout the world. Having the support of sister companies, puts WELL in a strong position to have 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;
    - WELL's EV trial in 2018 was a successful endeavour in understanding the behaviours of consumers with regards to time of use charging profiles and the expected impacts to cost reflective pricing.
    - The trial indicated that consumer behaviour is centred more around sustainability than supporting peak demand reduction. This is likely due to the fact that consumers sampled in the trial were early adopters.
- 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 make informed choices around new technology, WELL has published a cost reflective price which signals options that optimise the value delivered by the network for consumers.

Currently the uptake of PVs in Wellington is low compared with other regions but further increases in PV installations may drive investment changes going forward.

Overall, the greatest benefits for consumers in Wellington are most likely to come from low cost off-peak charging of EVs based on developing appropriate pricing signals, in conjunction with retailers. This is likely to continue until PV with battery storage becomes both affordable and effective to provide another option to help consumers enable a reduction in network peaks.

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; and
- On demand load management via the existing ripple control system.

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 submitted to the Commission as part of its review of the Input Methodologies (IM) that a revenue cap approach, which mitigates the consumption forecasting uncertainty, is a more appropriate form of price control. This was in comparison to the price cap approach, which exposes electricity distribution businesses to losses due to forecasting error. Pleasingly the Commission announced that a revenue cap will be used for the DPP from 2020 and for Customised Price Path (CPP) applications immediately. This brings the New Zealand regulatory regime in line with Australia and the United Kingdom. WELL moved onto a revenue cap from 1 April 2018 as part of the SCPP for readiness expenditure.

The new DPP price path starts on 1 April 2020 but it is expected that WELL will move onto this when the CCP 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. WELL is working with the Commission and industry to reset prices and quality for the new DPP.

Apart from the Low Emission Vehicle (LEV) Contestable Fund, which is a Government funded initiative, there is no research and development or innovation funding to trial new technology. It is expected that application mechanisms under Part 4 Clause 54Q of the Commerce Act 1986 may 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

The asset management framework which WELL operates to 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 the asset management policy, asset management strategy, asset strategies, the investment plans and the delivery phase as shown in Figure 4-1.

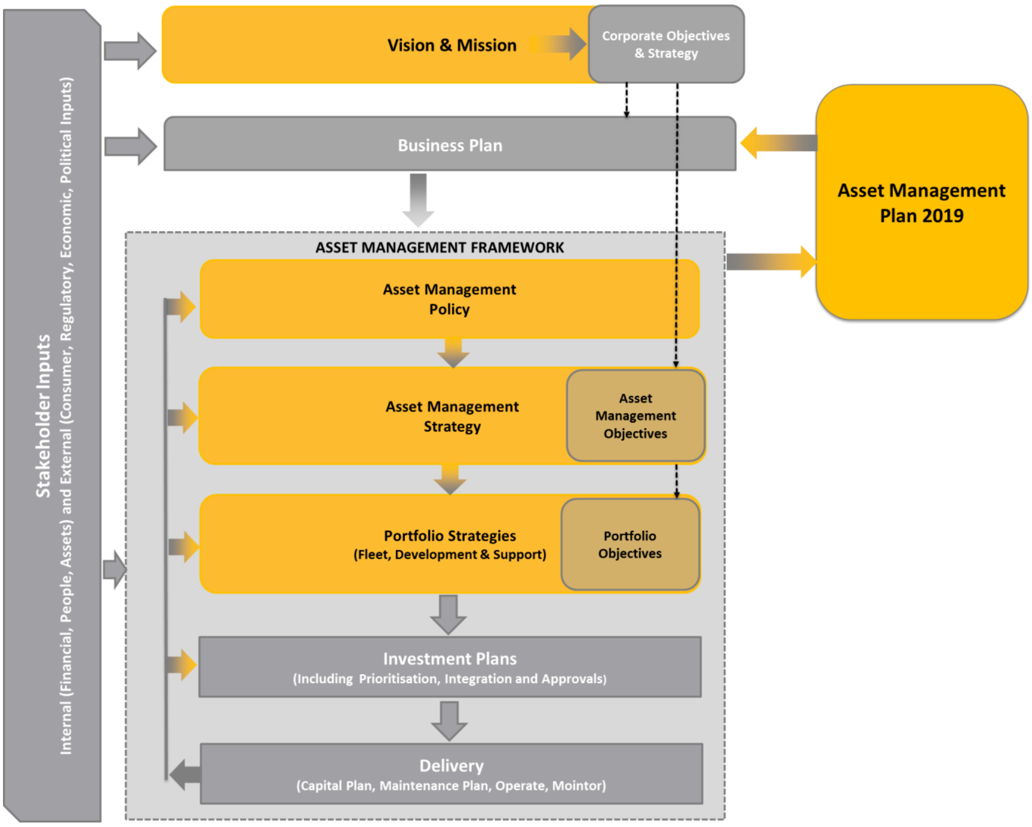


Figure 4-1 Asset Management Framework

Each component of the Asset Management Framework is described below.

4.1.1 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 policy has the following objective:

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

The policy also states that 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.

4.1.2 Asset Management Strategy

The asset management strategy developed by WELL has been established to deliver the service levels described in Sections 5 and 6.

WELL then divides its asset strategies into the following categories:

1. Fleet strategies focusing on operating, maintaining, replacing and disposal of existing network assets, associated with WELL's existing network infrastructure. These are discussed in Section 7;

2. Network development strategies dealing with the changing consumer demand, any new developments, and impact of emerging technologies. These are discussed in Section 8;

3. Emerging Technology strategies as discussed in Section 9;

4. Support System Strategies focusing on the upgrading, maintaining, and operating the IT support systems and other requirements for running WELL's business operations. These are discussed in Section 10; and

5. Resiliency strategy as discussed in Section 11.

4.2 The Investment Selection Process

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

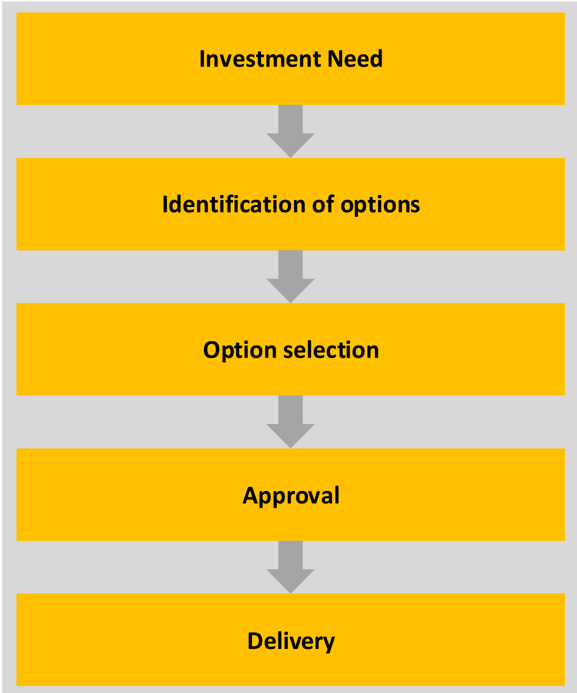


Figure 4-2 Investment Selection Process

4.2.1 Need Identification

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

4.2.1.1 Risk-based Approach

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

- Proactively: Reducing the probability of asset failure through safety-by-design principles, meeting security of supply criteria standards, capital and maintenance work programmes, 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 to identify trends; and

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

The risk of an asset failure is a combination of the likelihood of failure (largely determined by the condition of the asset) and the consequences of failure (determined by the impact on society, magnitude of any supply interruptions, the repair or replacement time, and the extent of any reduction in network operating security while the asset is being repaired). Assessment of this risk assists the process of deciding whether to phase out an asset through a planned replacement programme or allow it to continue in service, supported if necessary by additional inspection and preventative maintenance activity. The risks associated with each asset fleet and network area are discussed further in Sections 7, 8, 9, 10 and 11.

4.2.1.2 Prioritisation of Projects

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

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

Non-discretionary projects outside of the prioritisation process 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 PV (or other forms of DG), or by WELL in the case of grid-scale PV 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 stakeholders are achieved within allowances to balance the price/quality trade off. This is to align reliability with cost the consumers 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 high level need through to a preferred investment option that in turn is supported by a business case. This includes consideration of a list of appropriate options, refinement of the list to a short list of practicable options followed by detailed analysis and selection of a preferred option which is then documented in a business case for approval. The Works Plan is the repository for all potential 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. Changes to either plan are required as an input to the other plan (i.e. AMP changes that impact the order of work in the next 10 years will be factored into the next Works Plan prepared).

The process is as follows:

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

2. Approved recommendations are entered into the Works Plan and prioritised in terms of safety, budget, timelines and network criticality.

3. The Works Integration Team develops, prioritises and allocates budget for the annual Work 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.

4.3 Asset Management Delivery

The Works Plan is the repository for all potential 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 senior management for Board updates.

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 GM – 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.

Fault Response, Maintenance and Minor Capital Works - Northpower

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

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, on site cable mark-outs, sub transmission standovers and provision of buried asset plans provided to third parties;
- Minor connection services and livening; and
- Management services – management of the low voltage network, 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.

Contestable Capital Works Projects (Northpower, Downer, Connetics etc.)

Contestable capital works include:

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

Contestable capital works projects are generally competitively tendered. They are delivered under either independent contractor agreements (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 such as KPIs or KRAs, defects liability periods, and insurance and liability provisions to manage the exposure of WELL and to reflect the requirements of the HSW Act 2015. All contracts are managed on an individual basis, and include structured reporting and close out processes including field auditing during the course of the works.

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

Vegetation Management (Treescape)

This outsourced contract 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 improved landowner awareness of tree hazards.

Management of this contract is handled by the Service Delivery GM in a similar manner to the Northpower FSA with regular meetings and performance incentives in place.

Contact Centre (Telnet)

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

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 sub transmission 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. Intranets and extranets make the documents available to both internal users and external contractors and consultants. Generally, documents are intended to be reviewed every three years; however some documents, due to their nature or criticality to business function, are subject to more frequent reviews.

4.5 Asset Management Maturity Assessment Tool (AMMAT)

The Asset Management Maturity Assessment Tool (AMMAT) is provided in Appendix C, with a final average score of 3.0 across the six categories. The graph in Figure 4-3, extracted from the AMMAT, gives a summary of the results. Minor inconsistencies or gaps identified were in the areas of Continual Improvement.

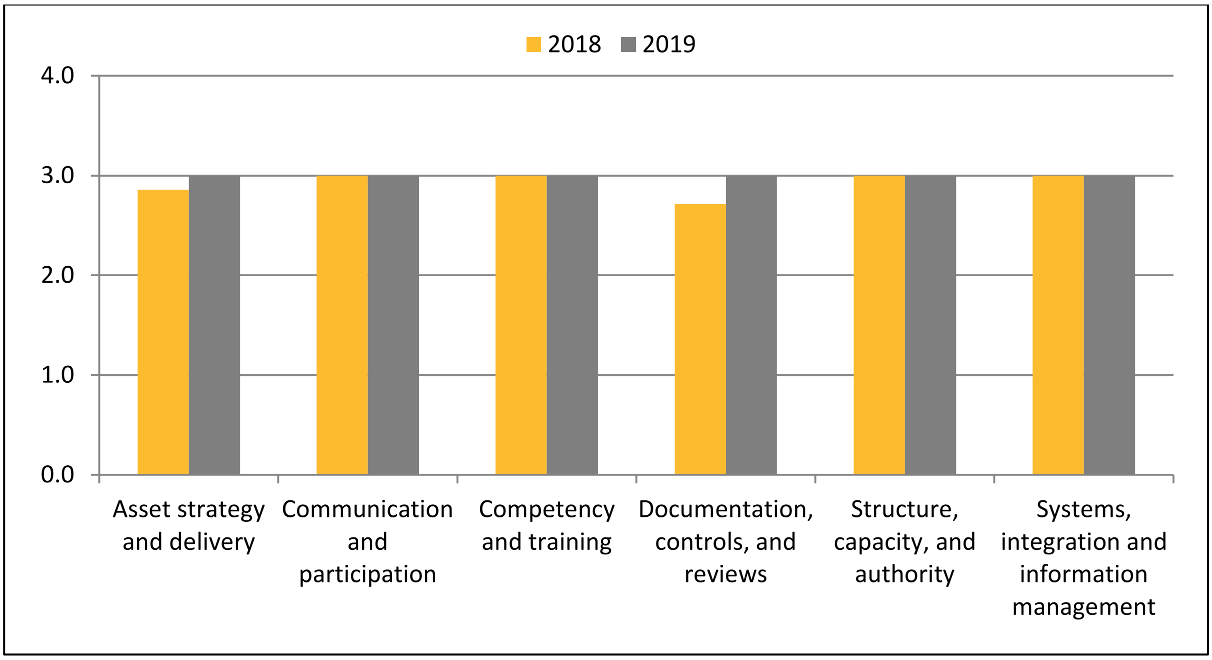


Figure 4-3 Summary of the AMMAT Assessment 2018 and 2019

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. At this stage, WELL has pushed toward Maturity Level 4 in the Performance and Condition Monitoring Category due to its use of Asset Health Indices (AHIs), Asset Criticality Indices (ACIs) and failure rates as well as the asset survival curves it has started to produce. Figure 4-4 shows the improvements made over the years to the AMMAT. The areas identified in the AMMAT to be lower than Maturity Level 3, and a brief description of the development strategy to get from the present maturity level to Level 3 is provided in Table 4-1.

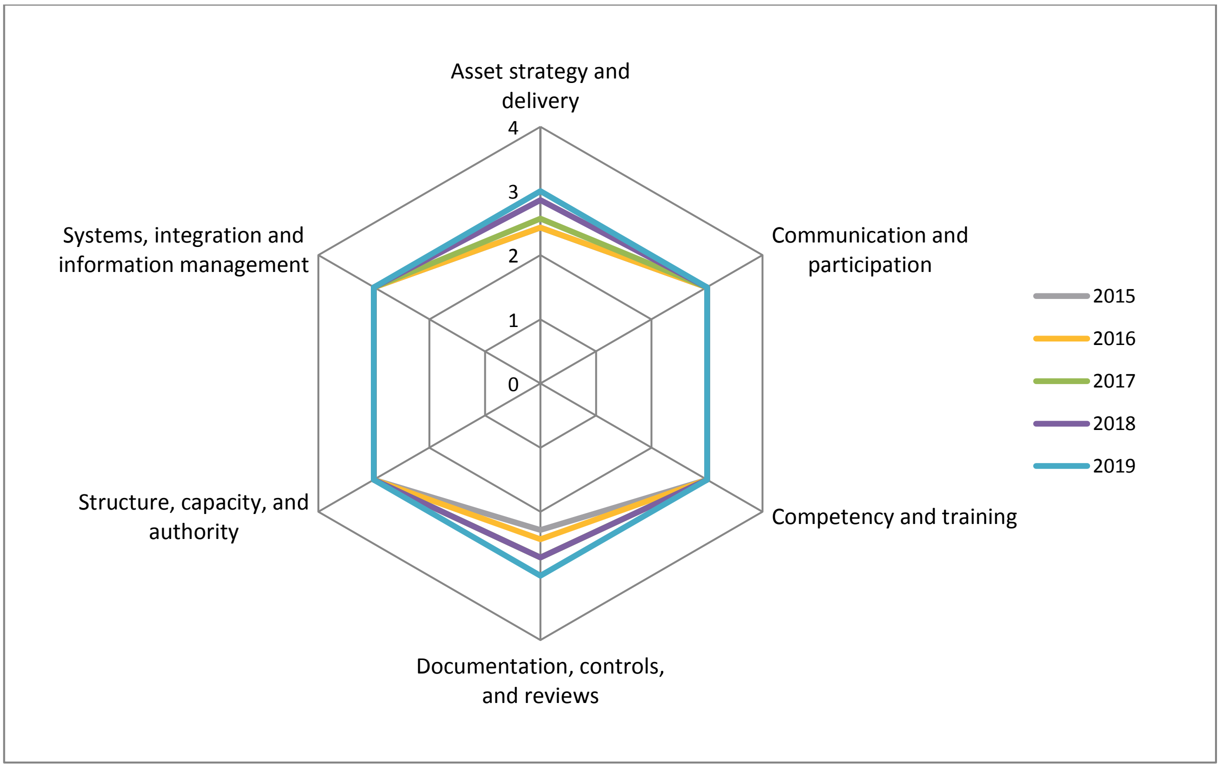


Figure 4-4 Yearly Improvements to the AMMAT

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 are developed to 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. Once these Asset Fleet Strategies have been developed (six have been completed thus far), they will be periodically reviewed and update to inform future AMP's.	Complete the Fleet Strategies for all assets on the network.

Table 4-1 Strategies for Improving Asset Management Maturity

4.6 Quality, Safety and the Environment (QSE)

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

- 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;
- Members of the public are not harmed by the operation, maintenance and improvement of WELL's assets;
- 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 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 appraised on issues and to provide guidance to management. As illustrated in Figure 4-5, a formalised Safety Leadership Structure is in place to help ensure that health and safety leadership is provided throughout the business.

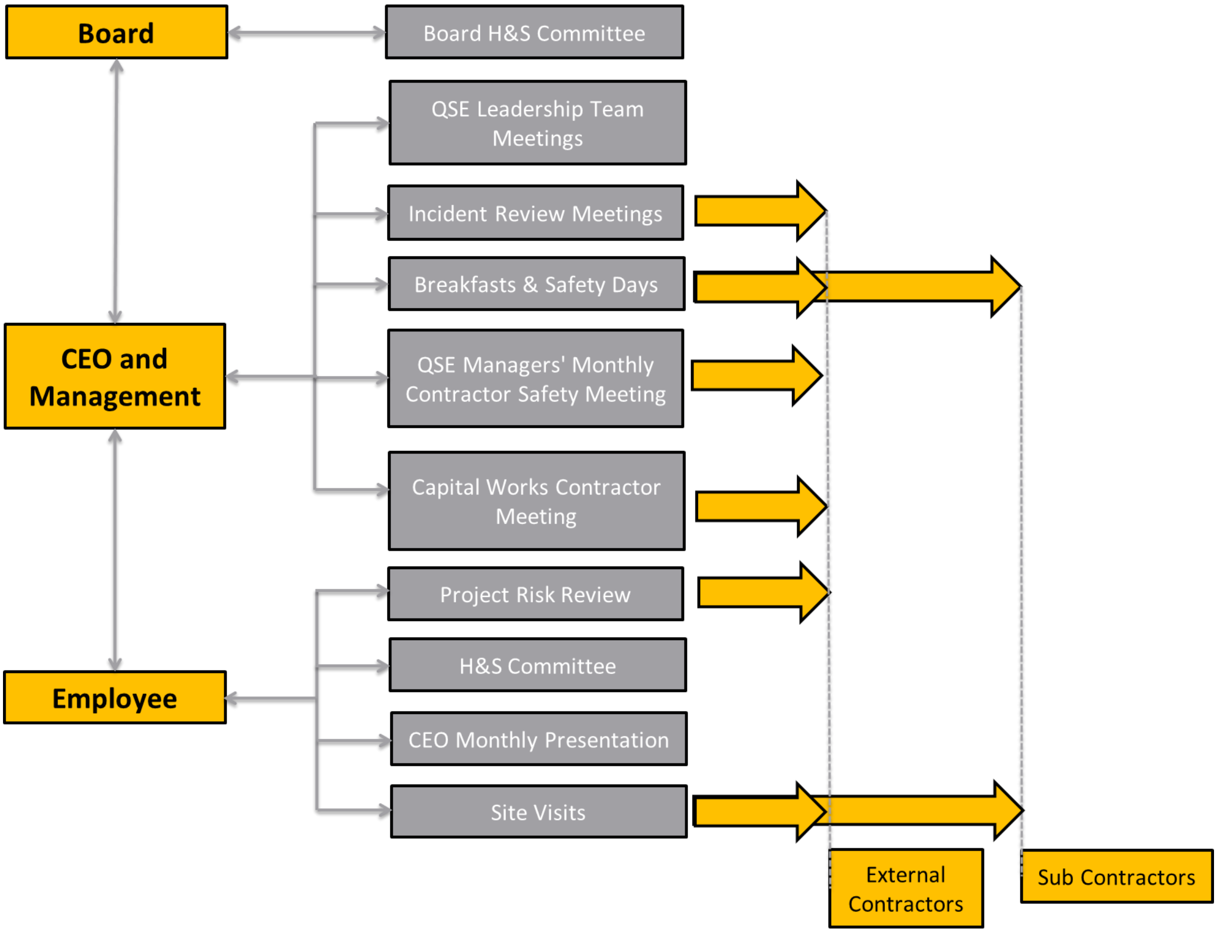


Figure 4-5 WELL's Safety Leadership Structure

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 of consultation, collaboration and coordination in adhering to safe work practices, making appropriate use of plant and equipment (including protective clothing and equipment), reviewing that controls are being managed and reporting of 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, with employees and contractors who are required to:

- Take all reasonable steps to ensure that business activities provide an outcome, which minimises environmental impacts and promotes a sustainable environment for future generations; and
- Take all reasonable steps to ensure the delivery of goods, products and services are to an acceptable standard and meet the quality expectations of the business.
- 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 on 4 April 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 includes assets that are installed in public areas and the management of these assets to ensure they do not pose a risk to public safety. The PSMS meets the compliance requirement for electricity distributors to implement and maintain a safety management system for public safety set out in Regulations 47 and 48 of the Electricity (Safety) Regulations 2010.

The PSMS also meets the requirements of NZS 7901:2008 Electricity and gas industries - Safety Management Systems for Public Safety. In 2018 the certification body Telarc reassessed WELL against the requirements of NZS 7901 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 2018 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"* 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 Add 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 2015 by formal contractual conditions and consultation, co-operation and co-ordination between all 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 7 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 the WELL CEO, keynote speakers and other subject matter experts.

4.6.3.4 Site Safety Visits

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

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 bi-annually by the CEO as part of the regular management reporting functions in line with the risk management framework.

The CEO is accountable for the performance of the business and as such the effectiveness of the controls being employed to manage the risk from occurring. While the CEO is held accountable by the Board, the management team have assigned responsibilities for ensuring controls are implemented and well managed so that risks are reduced to an acceptable level. The responsibility of controls are assigned to managers and bi-annually reviewed to ensure they remain relevant and that the risk environment has been assessed for new risks or changes to the risk profile. Some of the key controls are listed in Section 4.7.3.

4.7.2 Risk Management Framework

WELL's approach to risk management is illustrated in Figure 4-6.

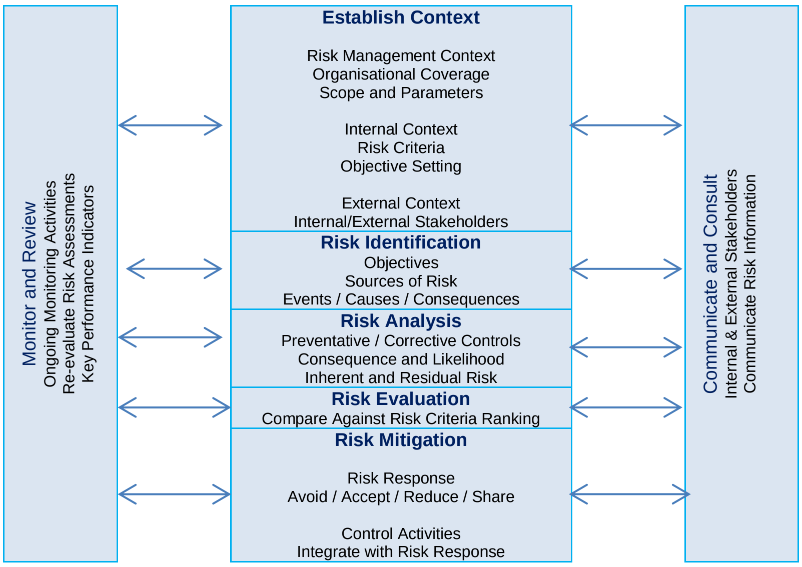


Figure 4-6 WELL's Risk Management Process

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). Consequence and likelihood tables have been established considering 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 4-7 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 4-7 Qualitative Risk Matrix

Risk Evaluation. Requires the evaluation of risk likelihood and consequence by appraising 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 2018, 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	Non-optimum starting price adjustment.	High	Medium
3	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
4	Taxation authorities dispute Business' position on tax treatments.	High	Medium
5	Injury or Damage caused or loss suffered to third parties.	High	Medium
6	Sub-optimal performance or failure of network assets.	High	Medium
7	Non-compliance with relevant laws, regulations and reporting requirements.	High	Medium
8	Non-compliance with the Health and Safety at Work Act 2015.	High	Medium
9	Exploitation of IT security.	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 190 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, therefore 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, because insurance cover is not factored into the debt risk premium of the WACC. As such, the customer retains the risk on the uninsured portion of the network even though the regulated line charges do not include an allowance for the recovery of the cost of retaining the risk. WELL does not insure its sub transmission 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 Levels

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 Service Levels are discussed in Section 6 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 change in 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 2018. This resulted in a 2018 LTIFR of 0.00 per million hours worked and a two year rolling average of 0.00.

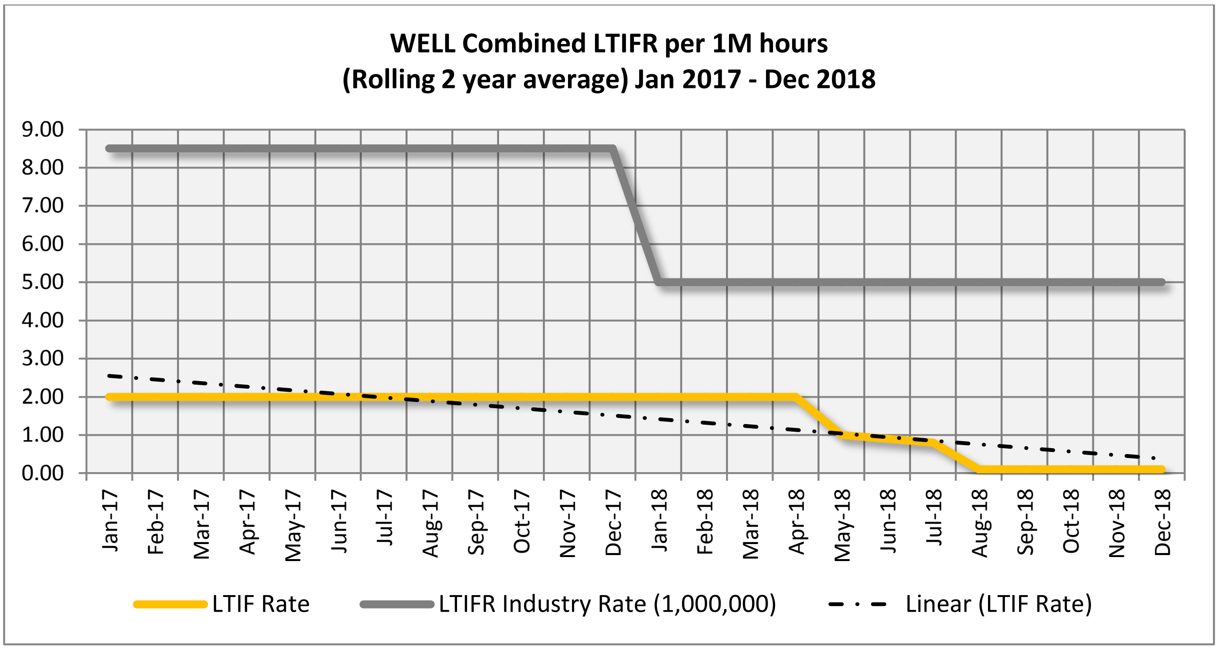


Figure 5-1 Lost Time Injury Frequency Rate

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 2015 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 2015 with reference to "notifiable injury, illness or incident".

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

WELL's staff and contractors recorded four Notifiable Events in 2018. This resulted in a 2018 TNEFR of 2.82 per million hours worked and a two year rolling average of 0.00.

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 2018 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 is consistent in 2018 with previous years with a total of 719 events, at the time of writing. Approximately 83% of all reported events were classified as minor, 16% were classified as moderate, whilst less than 1% were of a serious nature. The total number of proactive reports received during 2018 was 249, an improvement on the previous year's near miss reports. These 249 are further broken down to 52 near miss events and 197 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 300.

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 2012 levels, as shown in Figure 5-2. Monitoring will continue to help ensure that this trend is continued. A focus in 2017 was compliance with Temporary Traffic Management requirements, with a particular focus on public safety around worksites.

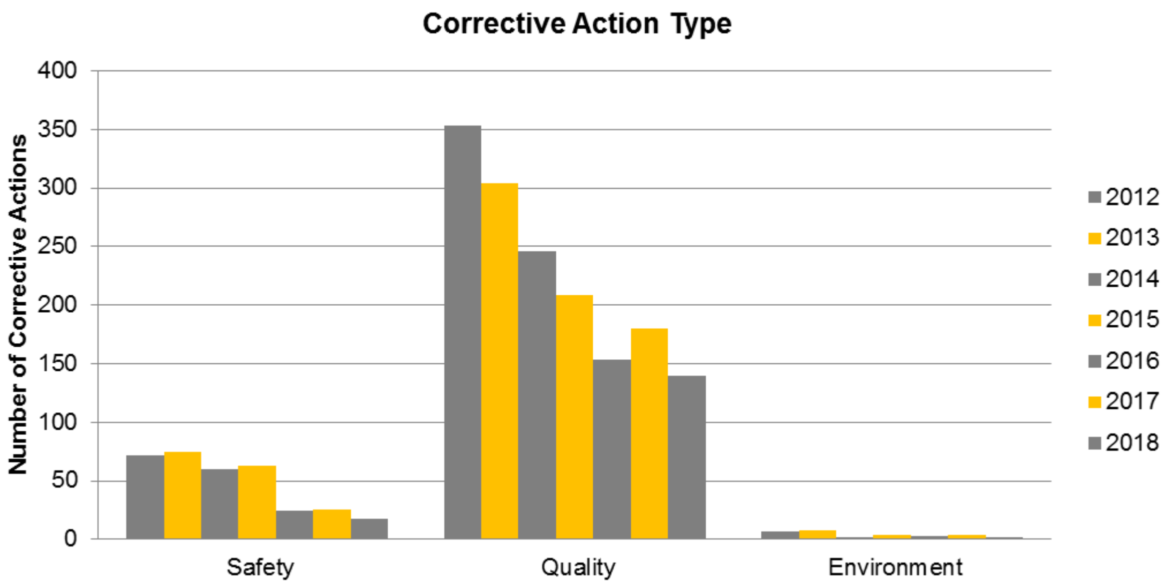


Figure 5-2 Corrective Actions arising from Assessments 2012-2018

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 600 assessments per year while reducing all three types of corrective actions.

5.1.5 Health and Safety Initiatives

During 2019 focus will be placed on the following areas to further improve performance:

- Reinforcement of WELL's new 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;
- Review 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 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.

5.2.1 Planning Period Levels

Table 5-1 illustrates the level of performance for each measure over the planning period together with key measures of network density.

WELL aims to maintain the high level of utilisation of asset 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. The utilisation levels are shown in Table 5-1.

	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]	59.0	30.15	5.6	40.3	185.5	12.3	15,956
WELL	47.5	39.51	4.7	122.8	486.2	35.3	13,761
Levels 2019-2029	>50%	>40%	<5%	-	-	-	-

Table 5-1 WELL Asset Efficiency Levels to 2029

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

5.3 Customer Experience Service Levels

It is important that WELL balances services that customers require with what value they place on these now and into the future. WELL uses the insights received from customer engagements to test the service levels provided and inform investment plans for the planning period. In addition, WELL is exploring a number of initiatives to improve customer service levels.

WELL is establishing 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

[20] Values as per the Pricewaterhouse Coopers (PwC) Electricity Line Business 2018 Information Disclosure Compendium.

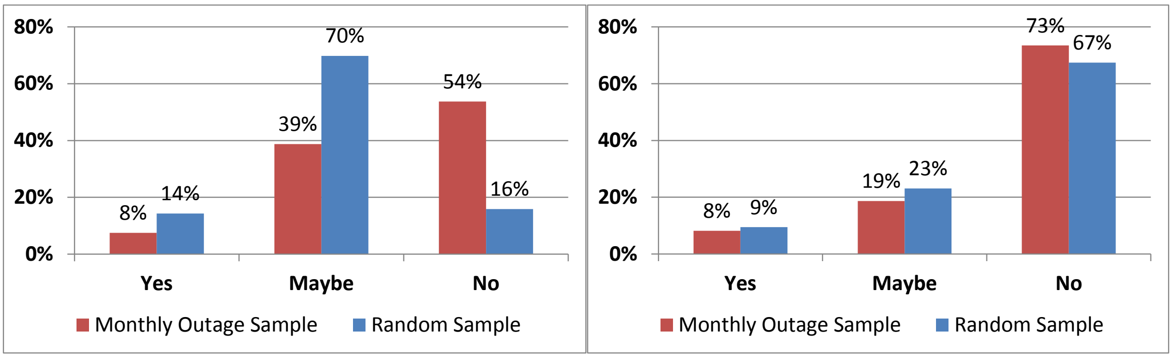
- Adding self-service tools to allow customers to start the order and/or enquiry process. This will help streamline the front end of this process and will guide customers through the process.

The updated website information and first phase of self-service tools is expected to be 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 by 2020.

The EPR has an industry-wide focus on energy hardship as one of their key recommendations. To this effect WELL is partnering with ERANZ to implement a pilot programme, currently titled 'EnergyMate'. The Wellington portion of the EnergyMate programme will target customers in the suburb of Porirua with a personalised visit, aimed at developing a plan for managing their energy use; improving the energy efficiency of their homes and connecting them with agencies who can provide financial support. This programme will help WELL to develop communication tools which can be used by low income customers to increase their understanding of how they can more easily afford energy use. The aim is to ensure that families can afford to maintain warm and healthy homes. The pilot programme will be reviewed upon completion before any further rollout.

5.3.1 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. WELL conducted a once off survey of a random selection of customers ("Random Sample") to enable a comparison with the monthly survey group perceptions. The results are shown in the charts below for two key cost-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 5-3 Sample of 2018 Customer Survey Results

For Question 1 (Q1), the results from each sample differ greatly for 'Maybe' and 'No' responses, however they are consistent in indicating that customers are not prepared to pay more for fewer power cuts. It is worth mentioning that for the Monthly Outage Sample group, the 'No' response has decreased from 85% in 2017 to 54% in the current year. Further analysis is required to determine the reasons for this change.

The results for question 2 (Q2) are more consistent between the two groups and, in combination with the responses to Q1, 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 5-4.

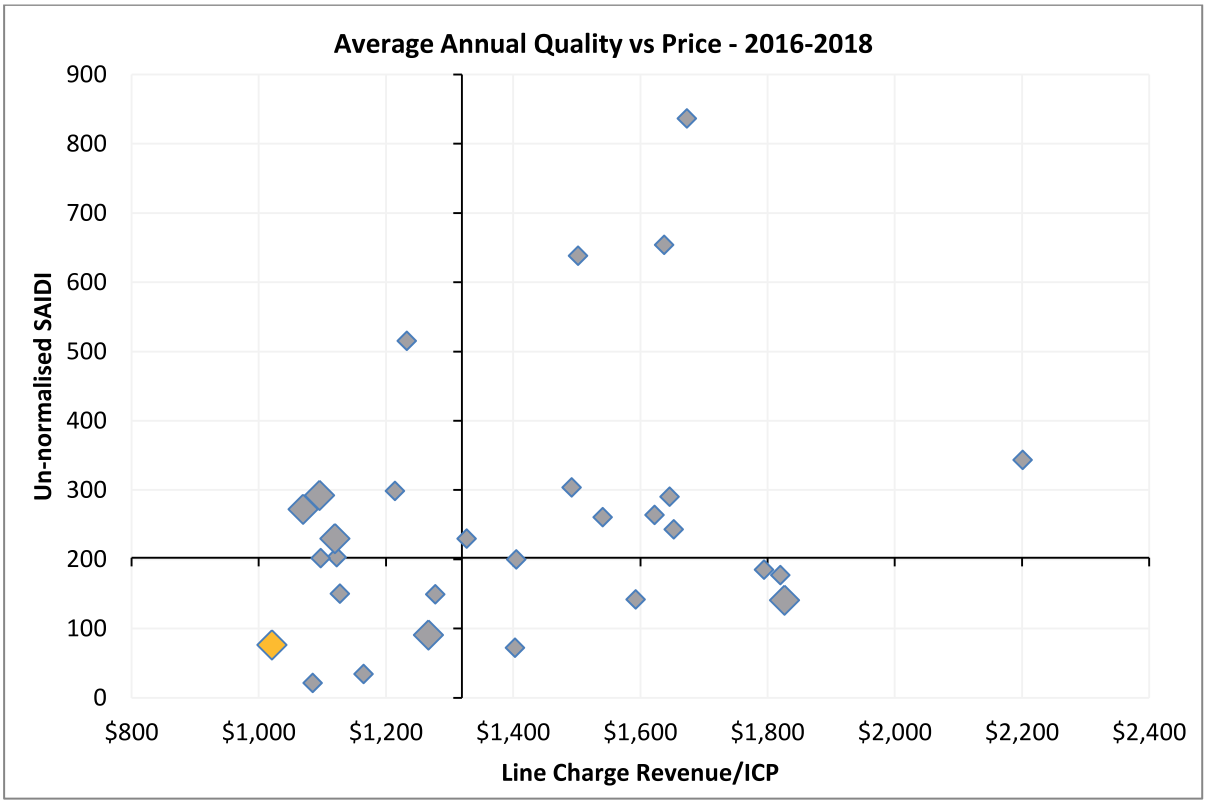


Figure 5-4 Quality – Price Comparison

In the past year, WELL has also engaged with targeted 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 a recent visit to residents of a street in Kingston impacted by a prolonged outage, and (WELL initiated) discussions with community associations in the Blue Mountains, Pauatahanui and Horokiwi areas. WELL has used these experiences to identify gaps in performance and develop plans to improve services. WELL's intention is to expand these programmes and use the engagement to help improve its services for customers.

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

In addition to monitoring customer's preferences and Contact Centre performance, WELL also measures power restoration service level targets, described in Section 5.3.2.

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

5.3.2 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 consumers: Urban and Rural. These service levels reflect previous feedback from consumers 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 good customer service and reliable, effective information flow is therefore a priority. To continue providing effective information to customers, WELL sets and tracks performance targets for the contact centre, covered in section 5.3.3.1 (Contact Centre Service Levels) below. 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 5-5.

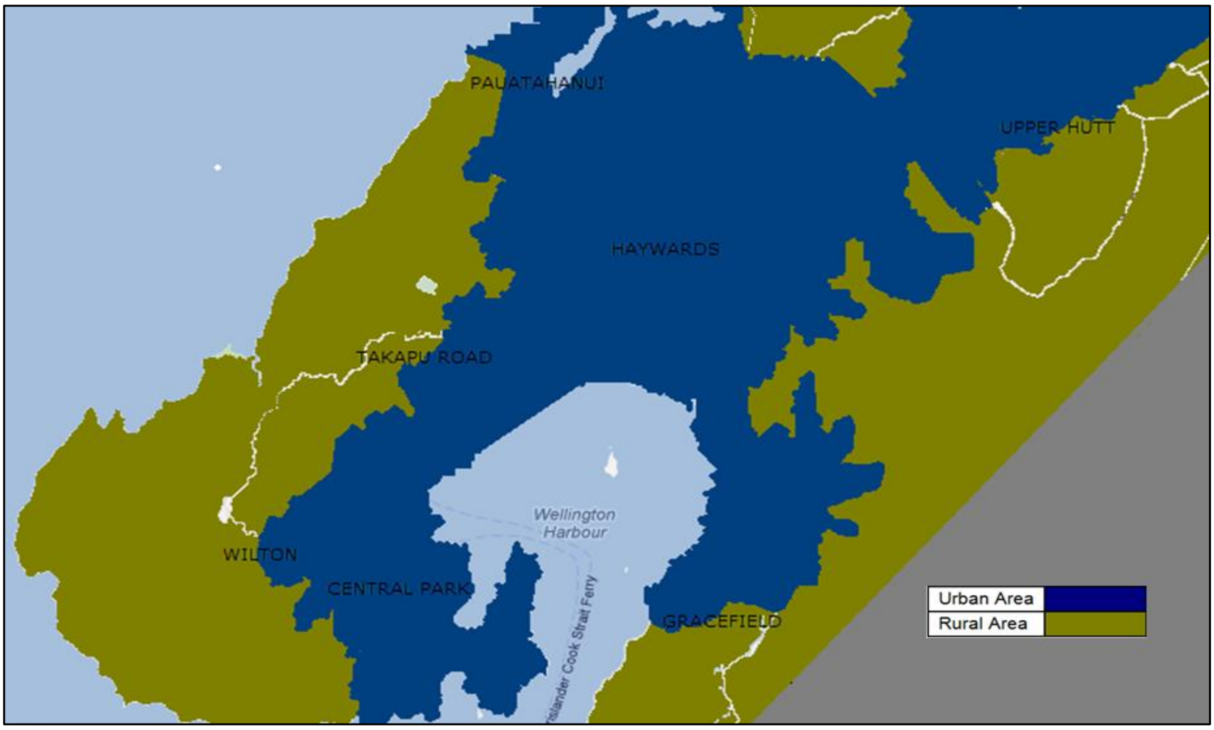


Figure 5-5 Location of Customer Category Areas

5.3.2.1 Planning Period Targets

The targets for the power restoration service levels remain consistent over the planning period 2019-2029, 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 2019-2029

5.3.3 Contact Centre Service Levels

WELL has developed a set of key performance indicators (KPIs) and financial incentives that provide service level targets for the Contact Centre (Telnet). These service levels have been in place since 2013. Due to the high level of consumer satisfaction with Contact Centre performance (90% to 94%), it is expected the targets and performance measures will remain broadly the same for the planning period from 2019 to 2029.

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 agent performance through continuous additions to and improvement in knowledge base content;
- Expansion of the call observation programme to include calls from non-dedicated (overflow) agents; and
- Improved systems interfaces to reduce the amount of agent manual data input required for outage notification updates, reducing the opportunity for human error and improving the flexibility of the outage notification system to better respond during major network events.

5.3.3.1 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 2019 year.

SL	Service Element	Measure	KPI	2018 Actual
A1	Overall service level	Average service level across all categories	>80%	82.6%
A2	Call response	Average wait time across all categories	<20 seconds	15.4 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	<4%	3.3%

Table 5-3 Contact Centre Performance

5.3.3.2 Planning Period Targets

The Contact Centre service level targets are to provide consistent performance over the planning period 2019-2029. 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 2019-2029

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Section 6

Reliability Performance

6 Reliability Performance

Electricity is an essential service for the community. Wellington's electricity network, although reliable due to its underground cabling, can be vulnerable to damage from external events. 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 this reason, WELL is committed to providing customers with a reliable and secure electricity supply. WELL has consistently demonstrated this commitment by undertaking reliability improvement initiatives to further progress the performance of the network, some of which are detailed below:

- The worst performing feeder improvement programme such as work undertaken to improve the quality of supply experienced for customers in the Whiteman's Valley supplied by Maidstone 10 (discussed further in Section 6.6);
- Analysis of incidents and outages to identify continual improvement opportunities. In 2018 this included for example, a greater use of portable generators to reduce the impact to consumers of planned outages; and
- Work undertaken based on 2017/18 reliability performance to improve practices in vegetation management as well as greater engagement with tree owners which has resulted in markedly improved vegetation management performance (discussed further in Section 6.5.1.3).

This section outlines WELL's reliability performance and explains how network reliability is managed within the price quality trade off provided to its consumers, discussed in Section 5. The SAIDI and SAIFI targets were both met in 2018/19 following two previous years where the limits for both were exceeded. This is a positive result supported by additional initiatives to further manage reliability.

The structure of the section is:

- How reliability is measured;
- Comparison of performance with industry peers;
- A summary of the overall reliability performance;
- Discussion on event types and controls;
- Worst performing feeder programme; and
- Regional performance.

6.1 Reliability Measures

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

- SAIDI[22] 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[23] is a measure of the total number of supply interruptions that the average consumer experiences in the measurement period. It is measured in number of interruptions[24].

[22] System Average Interruption Duration Index

[23] System Average Interruption Frequency Index

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

In accordance with the methodology established by the Commission, planned outages are weighted by 50% and 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[25], 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 for planning and operational purposes; and
- 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.

6.1.1 Reliability Performance Targets

The regulatory regime that applies to WELL sets reliability targets for each year from 2015/16 to 2019/20. The data set used to establish these performance targets is based on the 10 years from 1 April 2004 to 31 March 2014, known as the reference period.

The reliability limits for SAIDI and SAIFI are set at one standard deviation above the mean of the reference period. A compliance test applies which is based on not exceeding a limit in any two of three consecutive years. The targets and limits for WELL are presented in Table 6-1.

Regulatory Period 2016-2020	Annual SAIDI	Annual SAIFI
Target	35.44	0.547
Limit	40.63	0.625

Table 6-1 WELL Annual Regulatory Reliability Targets and Limits

Furthermore, the HSW Act caused many EDB's, including WELL, to review their live versus de-energised work policies and procedures. This has resulted in an impact to planned outages due to the increase in de-energised work compared to the reference period. In 2018/19 outages associated with planned work were partially reduced by deploying portable generators where safe to do so. Although this has been effective, it has come at a cost, and so will require additional future allowances if this practice is to continue.

The targets for SAIDI and SAIFI are shown in Table 6-2 and reflect WELL's view that, apart from the additional cost of using portable generation in support of de-energised work mentioned above, it is adequately funded to maintain network reliability at current levels. There is uncertainty around the calculation of targets from 2020/21 onwards, with the final determination not due until the 2020 DPP reset decision. Table 6-2 assumes that the SAIDI and SAIFI targets beyond 2020 account for the impact of the HSW Act 2015 and has been calculated using the same methodology as the 2014 determination.

[25] 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.

Regulatory Year	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2018/19	2027/28
SAIDI target	35.44	35.44	35.44	39.89	39.89	39.89	39.89	39.89	39.89	39.89
SAIFI target	0.547	0.547	0.547	0.594	0.594	0.594	0.594	0.594	0.594	0.594

Table 6-2 Network Reliability Performance Targets

The SAIDI and SAIFI targets against the historical performance are shown in Figure 6-1 and Figure 6-2. The 2018/19 year includes a forecast to account for the March 2019 month shown in dark blue.

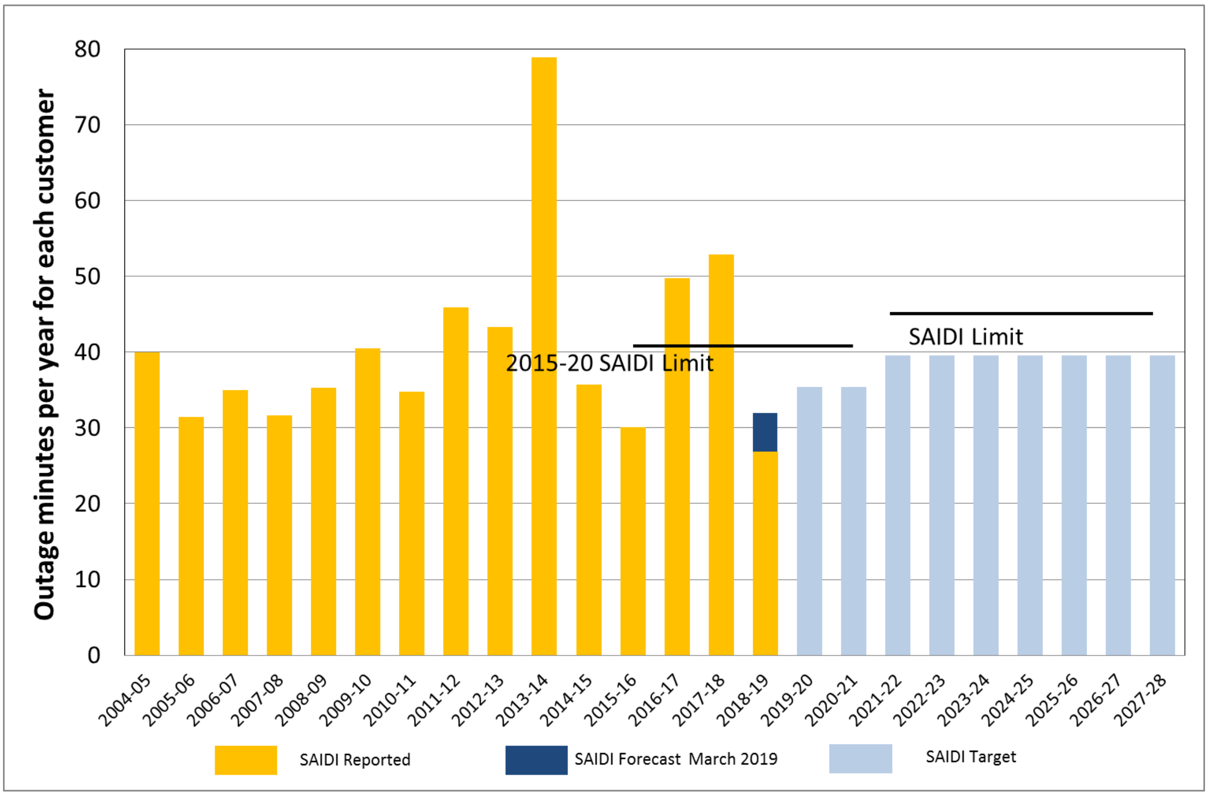


Figure 6-1 WELL SAIDI Performance

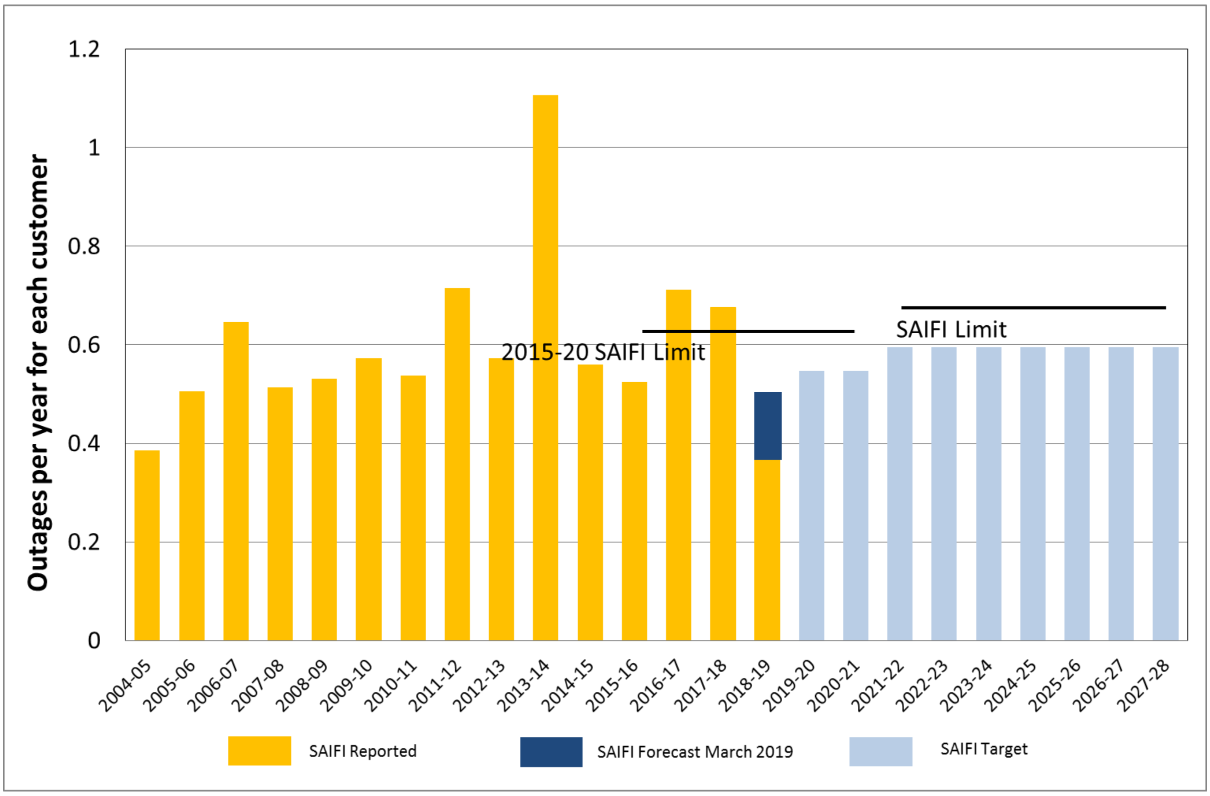


Figure 6-2 WELL SAIFI Performance

6.2 Industry Comparison

WELL was one the most reliable EDBs in New Zealand in 2017/18 as shown in Figure 6-3 and Figure 6-4. The data source is the annual Information Disclosures made by Lines Businesses and made publicly available in August 2018. 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).

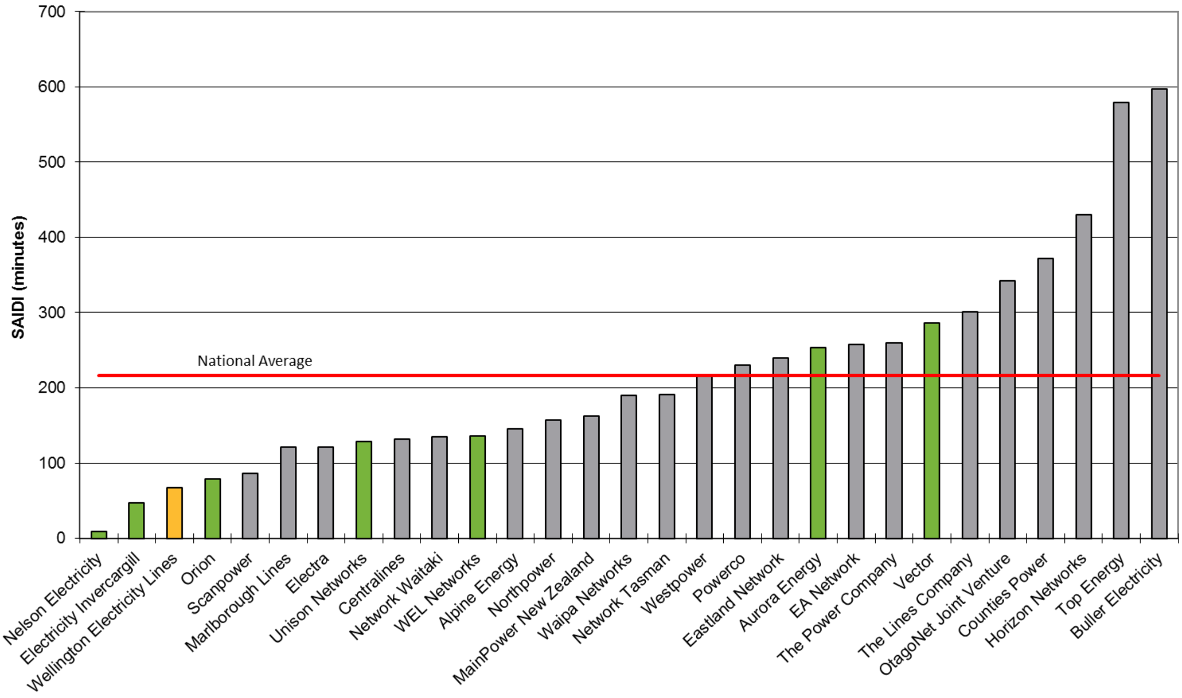


Figure 6-3 National SAIDI by EDB for 2017/18

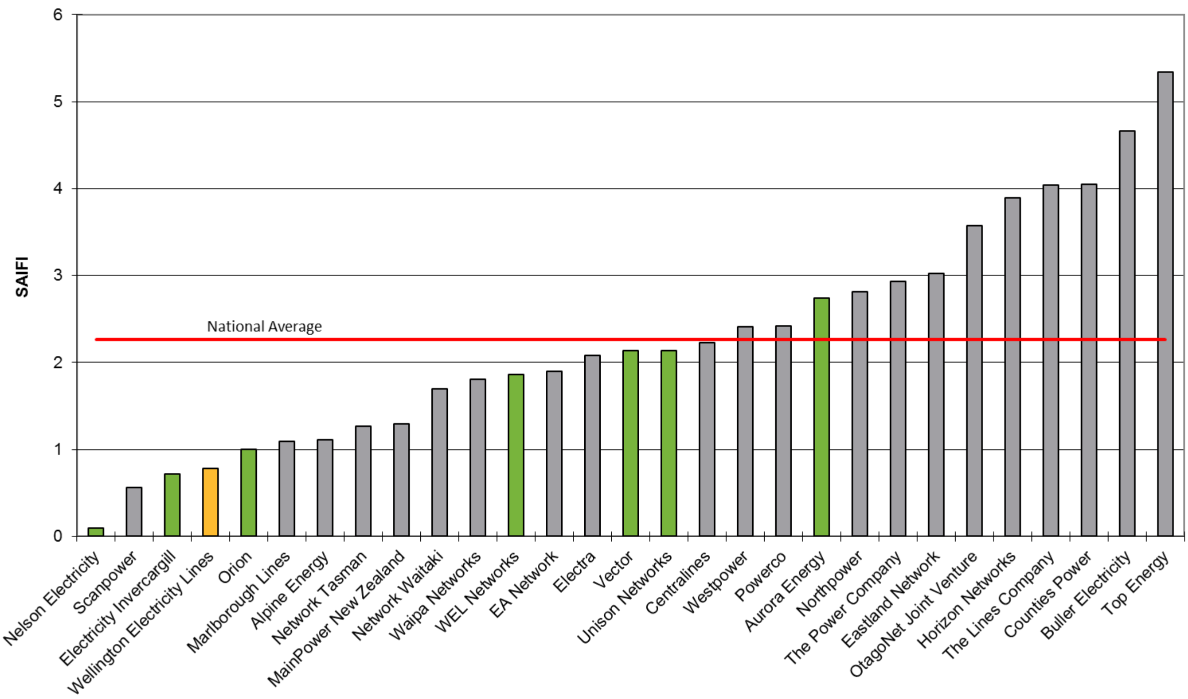


Figure 6-4 National SAIFI by EDB for 2017/18

6.3 Reliability Performance in 2017/18 and 2018/19

The total year-end SAIDI for 2017/18 was 52.856 minutes which was above the year end limit of 40.63 minutes. The total year-end SAIFI for 2017/18 was 0.680 interruptions and above the year end limit of 0.625. WELL's network performance for the 2018/19 regulatory year as at 28 February 2019 is currently under the annual limit of 40.63 minutes for SAIDI and under the yearly limit of 0.680 for SAIFI and is forecasted to end within target.

The change in WELL's SAIDI performance from 2017/18 to 2018/19 across a range of fault causes is shown as a waterfall chart in Figure 6-5, with the 2018/19 result being the year end forecast as of 28 February 2019. The fault causes represented in the chart are:

- Overhead Network faults;
- Underground Network faults;
- Substation faults;
- Car vs. Pole faults;
- Other Third Party faults;
- Planned work; and
- Major Event Days.

Overhead faults have been further separated into those caused by asset failure, and those that were not, for example vegetation, lightning, and animal. Major event days are listed as a separate category in order to account for normalisation.

Each of these categories is shown as the forecast 2018/19 result either being smaller (coloured in green) or larger (coloured in red) than their contribution to the 2017/18 result.

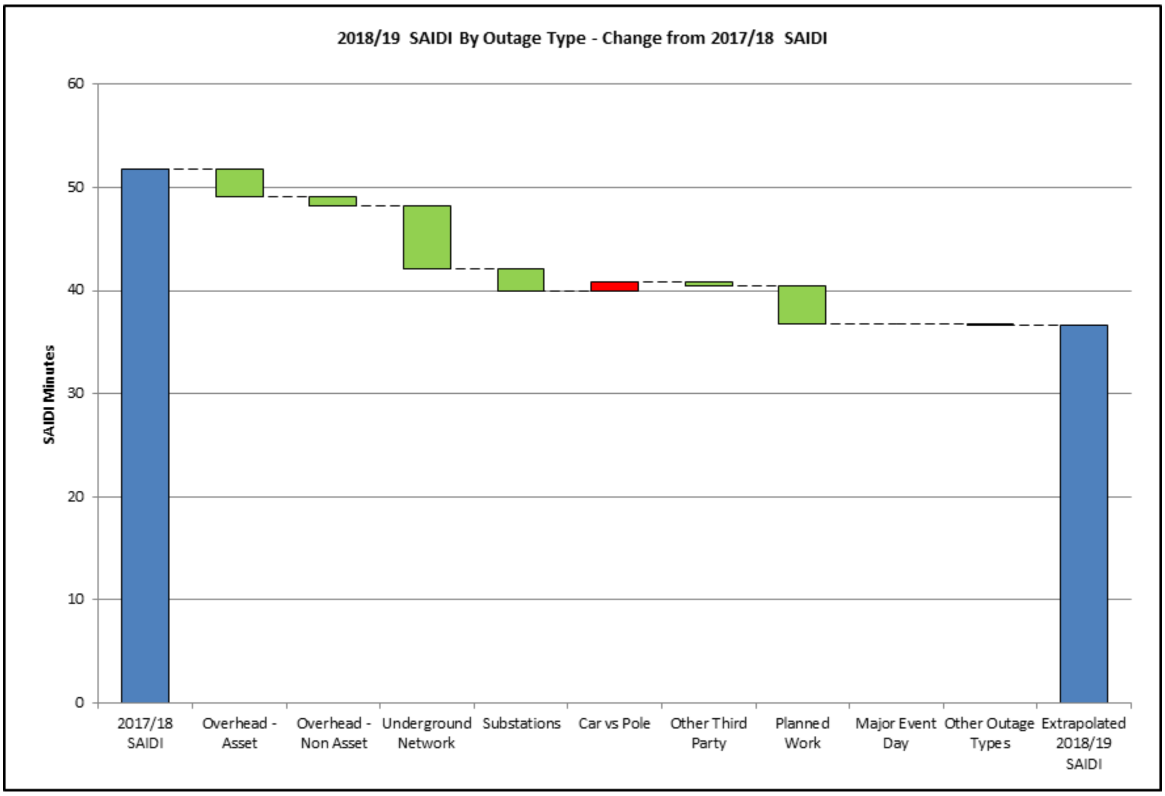


Figure 6-5 Forecast 2018/19 SAIDI Performance by Outage Type – Change from 2017/18

The chart shows improvements in the reliability performance of both the overhead and underground networks. It also shows a reduction in the impact of planned work. This reflects the effectiveness of the controls that are in place and is further detailed in Section 6.5.

6.4 Previous Exceedances of Quality Limits

WELL exceeded its SAIDI and SAIFI limits in 2016/17 and 2017/18. The causes of the exceedance between the two years were different. The 2016/17 reliability performance was dominated by the effect of abnormally turbulent wind conditions[26] on trees and the overhead network, while 2017/18 saw increased outages due to earthquake-related cable damage, car vs pole incidents, and the effect of the HSW Act on live line work. The changing causes between years shows that the non-compliance is not indicative of a trend of deteriorating performance.

Figures 6-6 to 6-7 present WELL's SAIDI performance from 2017/18 to 2018/19 as waterfall charts, comparing each year to the average performance during the reference period across the range of fault causes. The error bars represent the standard deviation in the reference dataset for each fault cause, to highlight the significance of any changes in performance.

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

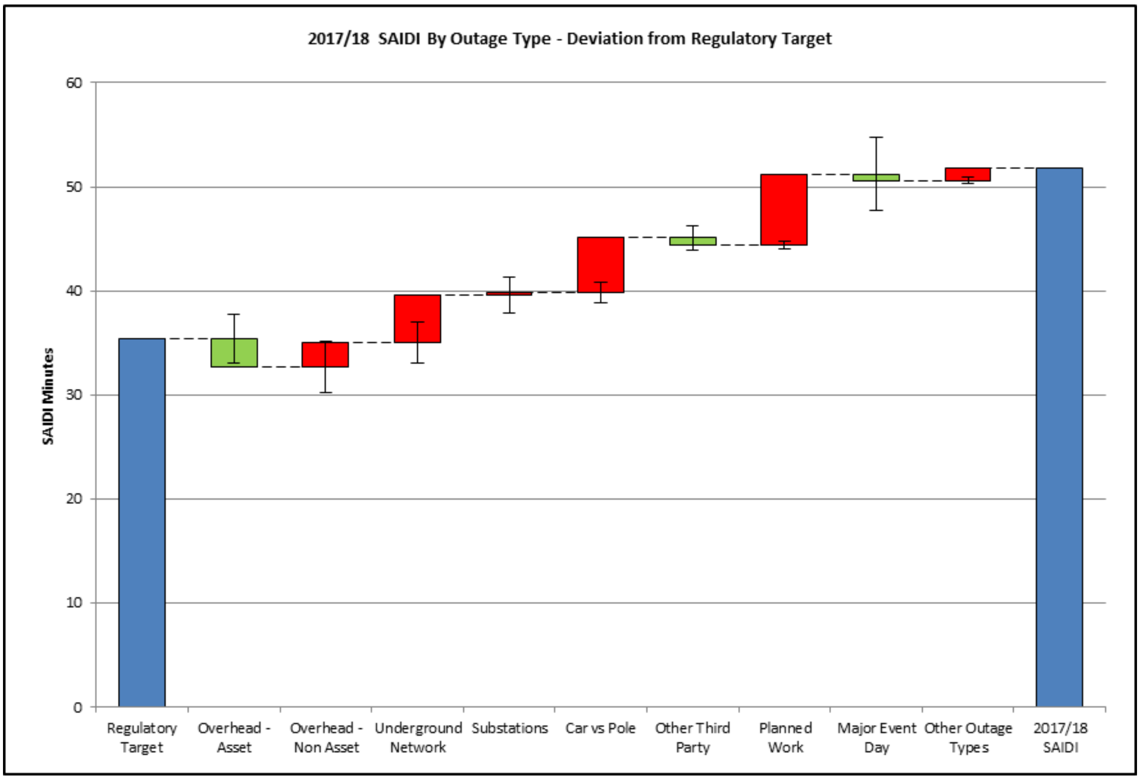


Figure 6-6 2017/18 SAIDI Performance by Outage Type

[26] The information related to the uplift in turbulence intensity has been sourced from NIWA.

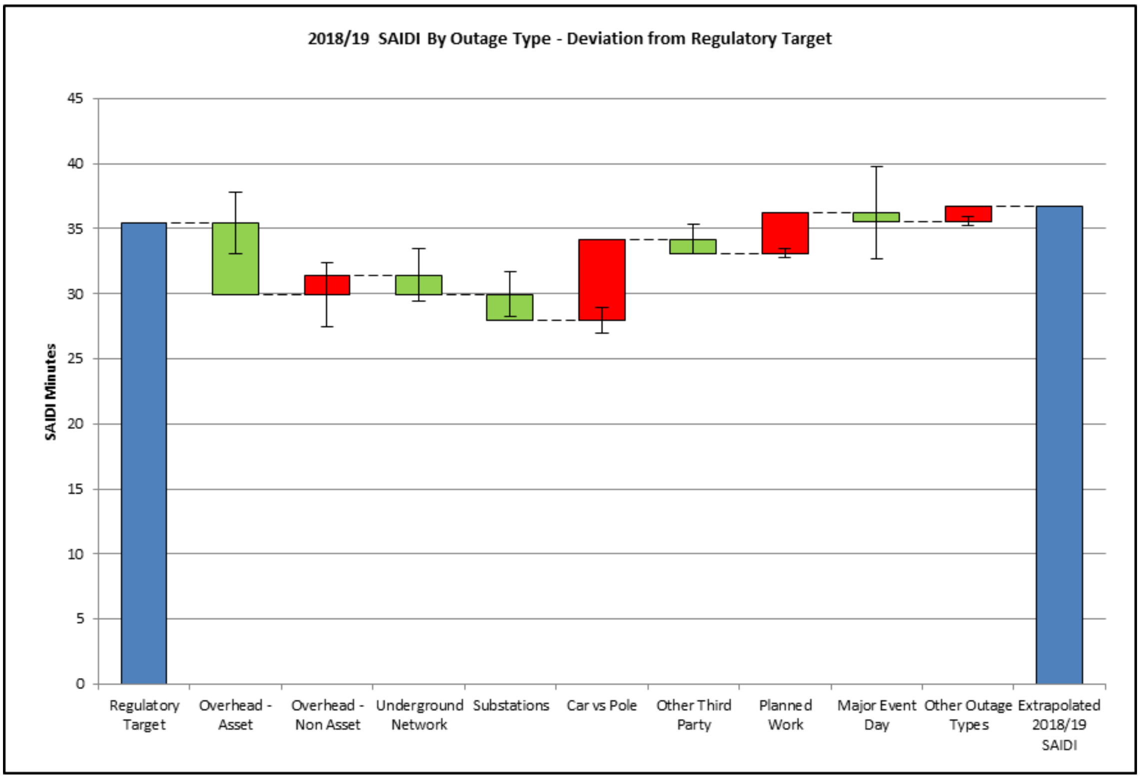


Figure 6-7 2018/19 SAIDI Performance by Outage Type

6.5 Reliability Performance Controls

WELL continuously reviews and updates its asset management practices and plans against the performance of the assets.

6.5.1 Performance and Controls by Fault Cause

The network SAIDI performance by fault cause from 2016/17 to 2018/19 (YTD) is shown in Figure 6-8. Major event days are not included in this chart due to the distortion caused by normalisation.

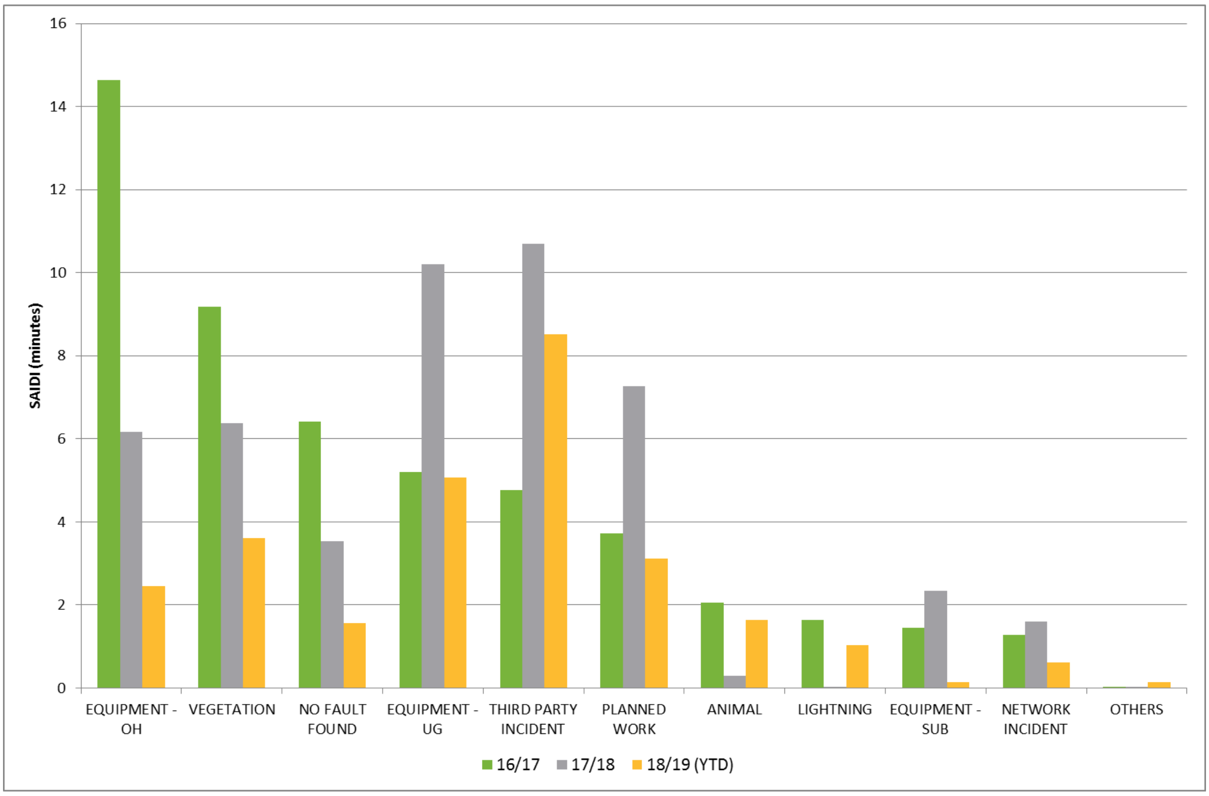


Figure 6-8 SAIDI Performance by Fault Type 2016/17 – 2018/19 (YTD)

A discussion on each of the fault cause categories and associated controls follows.

6.5.1.1 Planned Outages

The increase in planned outages is being driven by the amount of planned work being completed de-energised. WELL's view is that the regulatory limits should be adjusted to reflect the changes from the review of safe work practices and the material increase in planned outages that has resulted.

Since the 2016/17 and 2017/18 results, further review has resulted in taking a proactive approach to install portable generation, where safe to do so, to control SAIDI while work is completed de-energised. The customer benefits and additional costs involved in this approach are being captured to assess the practicality of returning planned interruptions as close to reference period levels as is safe and cost-effective.

Not all planned outages can be safely avoided through the use of generators, due to the need for generators to be connected and disconnected de-energised. To provide work planners with clear and consistent guidance about where the use of generators is appropriate, WELL has developed a generator decision matrix, shown in Figure 6-9.

Responsible to organise	Consideration	Priority Customers, Community Aspects[3]	CBD	Urban	Rural
SP PM/ WE* PM	Special Event[4]	Reschedule Work			
SP PM / WE* PM	Safety[1]	*Replan Job[7]*	*Replan Job[7]*	*Planned Outage*	*Planned Outage*
SP PM/ WE* PM	Generator Site suitability[2]	*Replan Job[7]*	*Replan Job[7]*	*Planned Outage*	*Planned Outage*
SP PM/ WE* PM	Outage < 0.03 SAIDI	*Generate or arrange with customer*	*Generate or arrange with customer*	*Planned Outage*	*Planned Outage*
SP PM/ WE* PM	Outage > 0.03 SAIDI[5]	*Generate*	*Generate*	*Generate*	*Generate*
SP PM/ WE* PM	Duration > 6 hours[6]	*Generate*	*Generate if possible*	*Generate if possible*	*Generate if Possible*

Notes

1: If it is unsafe to connect a generator or work cannot be carried out safely without risks to staff or public is not able to be controlled.
2: If the site is unsuitable for generator installation
3: Sewerage site, WETA, given sufficient notice (and finishing on time), generators may not be required. Community aspects include traffic lights at major intersections, police stations and the like. (**Contact customer to discuss work**)
4: Is there a special event on the day you have planned the work? Sport finals, Markets, ticker tape parade etc…
5: 0.03 is the target SAIDI figure per planned outage. Use the SAIDI calculator and compare the SAIDI cost of your outage with the cost of generation. An outage of 0.05 SAIDI will cost approximately $5,000, 0.03 will cost approximately $3,500
6: Negotiation with the customer is key, if an interruption greater than 6 hours is expected, first inform the customer.
7: Escalate and re-assess job to see if alternative methodology or smaller outage area can be achieved. If no alternative, then schedule planned outage.

Figure 6-9 Decision Making Criteria for Generator Use on Planned Work

The number of SAIDI minutes saved through the use of generators in support of planned work since recording began in February 2018, and the costs of doing this, through to July 2018 are shown in Figure 6-10. The reduction in cost per SAIDI minute generated is due to generators providing supply to larger areas in support of longer planned outages as contractors have gained confidence with their use.

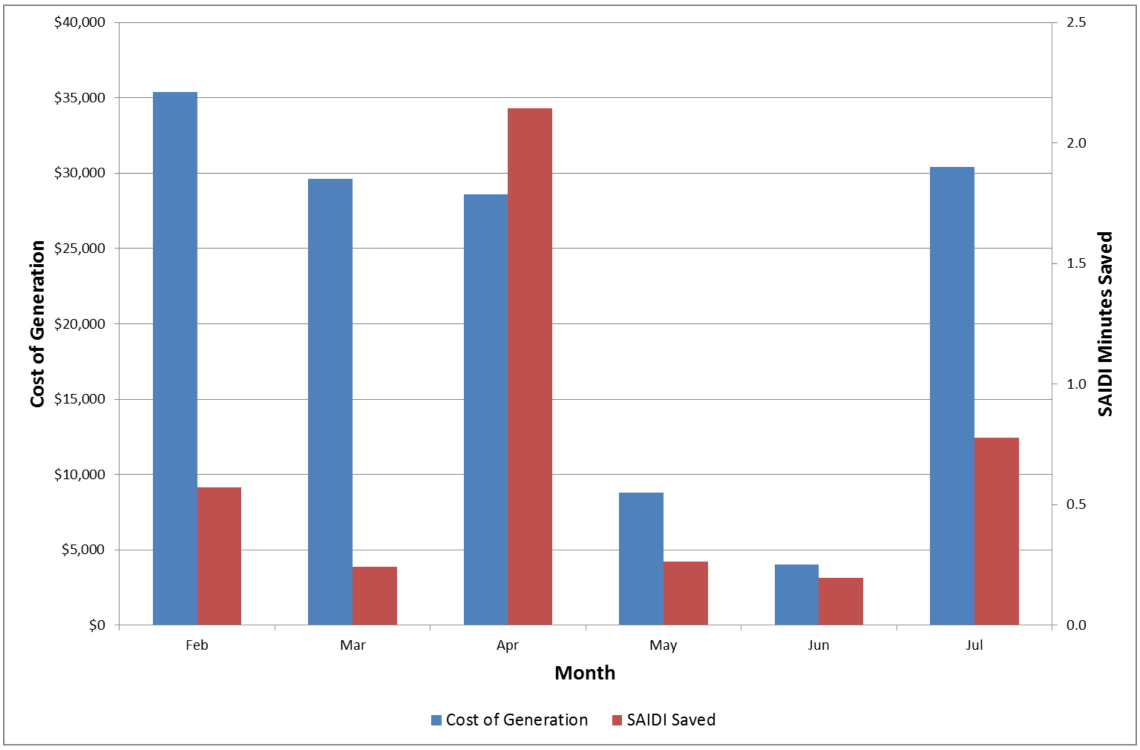


Figure 6-10 Cost/Benefit of Generator Usage – 2018

The controls in place for de-energised work are:

- Extending the time for approving outages to improve the planning of outages by providing more time to determine how best to reduce the impact to consumers and to also allow for a greater notification period for customers;
- Reducing the threshold for peer review of requests for planned outages to be for those greater than 0.03 SAIDI minutes, down from 0.05 SAIDI minutes, to ensure all reasonable avenues for minimising customer impacts have been considered;
- Introducing a risk assessment process on live work to ensure the decision whether to do work live or de-energised follows a consistent process considering both safety and network impact; and
- Trialling the cost effectiveness of using generators in 2018 as a means of limiting the impact of de-energised work.

WELL will continue to manage planned SAIDI as prudently as possible through the controls outlined above. However, it is anticipated that the impact of planned outages will not be reduced to the levels of the reference dataset, and will continue to be a challenge for WELL in meeting a consistent reliability target in the future.

Figure 6-11 Examples of Generators Supporting Planned Work

6.5.1.2 Overhead Equipment

The performance of the overhead network in 2018/19 year to date has been better than average. This reflects the benefits from the actions implemented following the Strata review of 2015/16 as well as the plans put into place after the 2016/17 exceedance of targets which was primarily driven by the overhead network.

These events generally occur during days of strong winds or stormy weather and the resultant overhead equipment failures are often due to failed connectors. The relative SAIDI impact of different overhead equipment failure fault causes is shown in Figure 6-12.

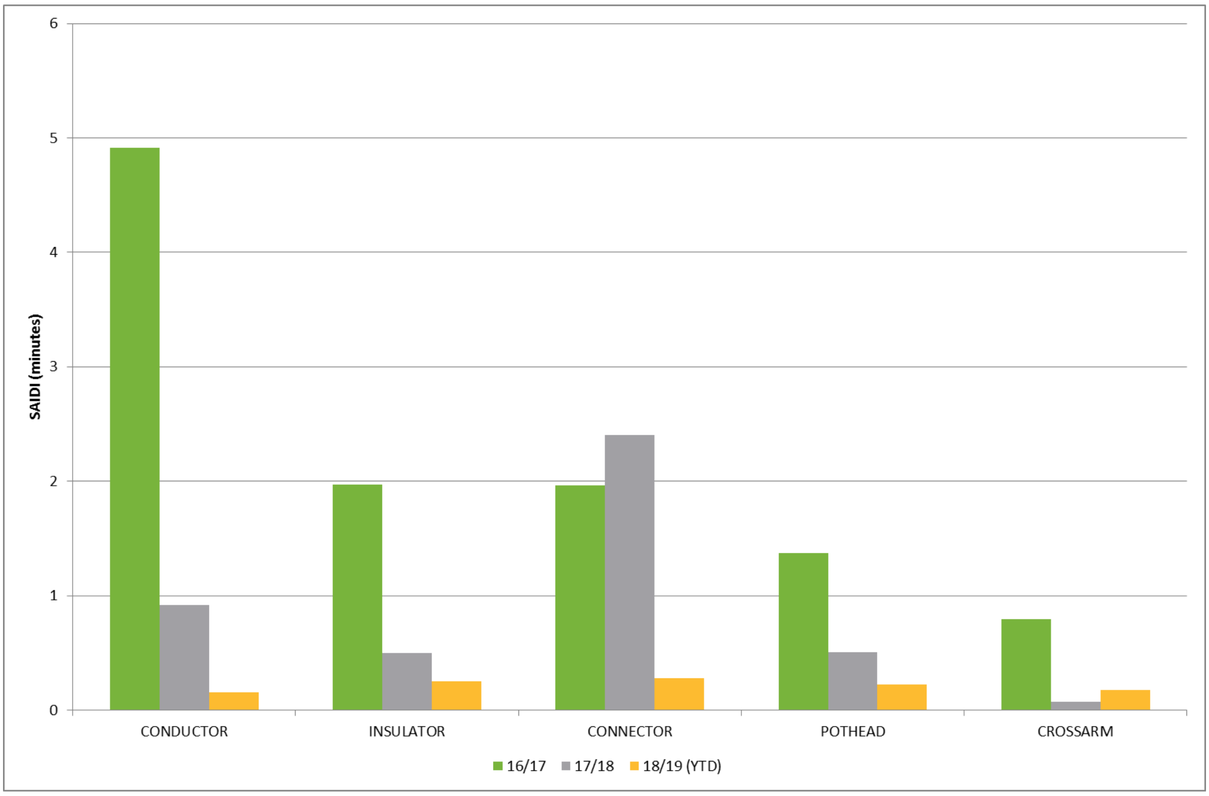


Figure 6-12 SAIDI Impact of Overhead Equipment Failure as the Fault Cause

Specific controls for overhead related events are:

- Targeting the worst performing feeders. This is a programme which has historically delivered good results in terms of improving feeder performance as discussed in Section 6.6;
- Undertaking pole, cross-arm and insulator replacement programmes;
- The introduction of leading indicators such as pole and conductor degradation rates based on actual sampling and testing programmes as discussed in Section 7;
- Adoption of the Gelpact cover to improve the corrosion resistance of Ampact connectors; and
- Risk assessment of 33kV lines before any planned work that would place the substation they supply on N security.

6.5.1.3 Vegetation

The number of vegetation faults experienced in 2016/17 resulted in a further review of vegetation management processes and adoption of a more risk-based approach being undertaken by WELL and its vegetation management contractor, Treescape. WELL's vegetation management up to 2017 had been based on a five-yearly inspection cycle across the network. WELL increased its vegetation management budget from May 2017 so that Treescape could return to the most affected feeders for an out-of-cycle round of vegetation survey and cutting, while continuing with the five-yearly surveys that had been scheduled for the year. Figure 6-13 shows the SAIDI impact of vegetation faults, which has been declining since 2016/17, indicating the effectiveness of this approach.

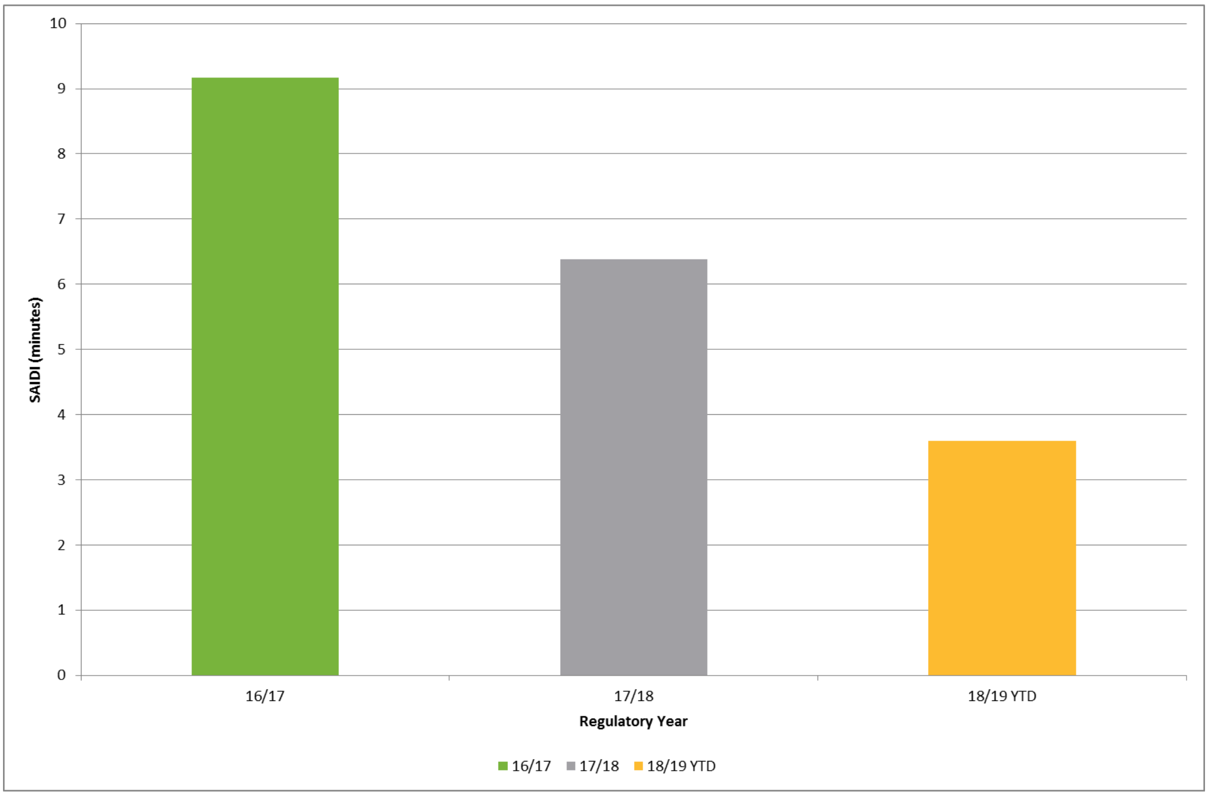


Figure 6-13 SAIDI Impact of Vegetation as the Fault Cause

In conjunction with this approach, 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.

Figure 6-14 Bark Blown onto Overhead Conductors

Specific controls for vegetation events are:

- Increased vegetation contract in 2017 which has helped reduce vegetation faults in 2018/19, this has been further increased in 2019;
- Increased vegetation work on shorter survey cycles for worst performing feeders to reduce vegetation faults;
- Introduction of a risk-based approach to tree trimming in 2017 considering location of the tree along the feeder and proximity and type of tree which allows vegetation spend to be focussed on high priority areas;
- Reinforced response to issued Cut or Trim Notices, including increased customer engagement with local authorities regarding street trees; and
- Installation of covered conductors in four trial locations to assess their effectiveness at reducing risk from vegetation.

Figure 6-15 Covered Conductor Trial Installation Before (left) and After (right)

6.5.1.4 No Fault Found

Most of the incidents which are listed as ‘no fault found’ occur during stormy weather and therefore were most likely the result of vegetation or line clash short-time events.

After a ‘no fault found’ event, the affected feeder is re-patrolled during daylight hours to identify possible causes that may not have been apparent during the fault. However there will likely be instances where the cause of the interruption cannot be identified with any certainty.

6.5.1.5 Underground Equipment

Failures in underground equipment are generally due to cable joint or termination failures. Cable systems themselves generally have a long life and high reliability as they are subject to fewer environmental hazards than overhead assets. Underground equipment faults have shown an increase in 2017/18 and a decrease in 2018/19 as shown in Figure 6-16.

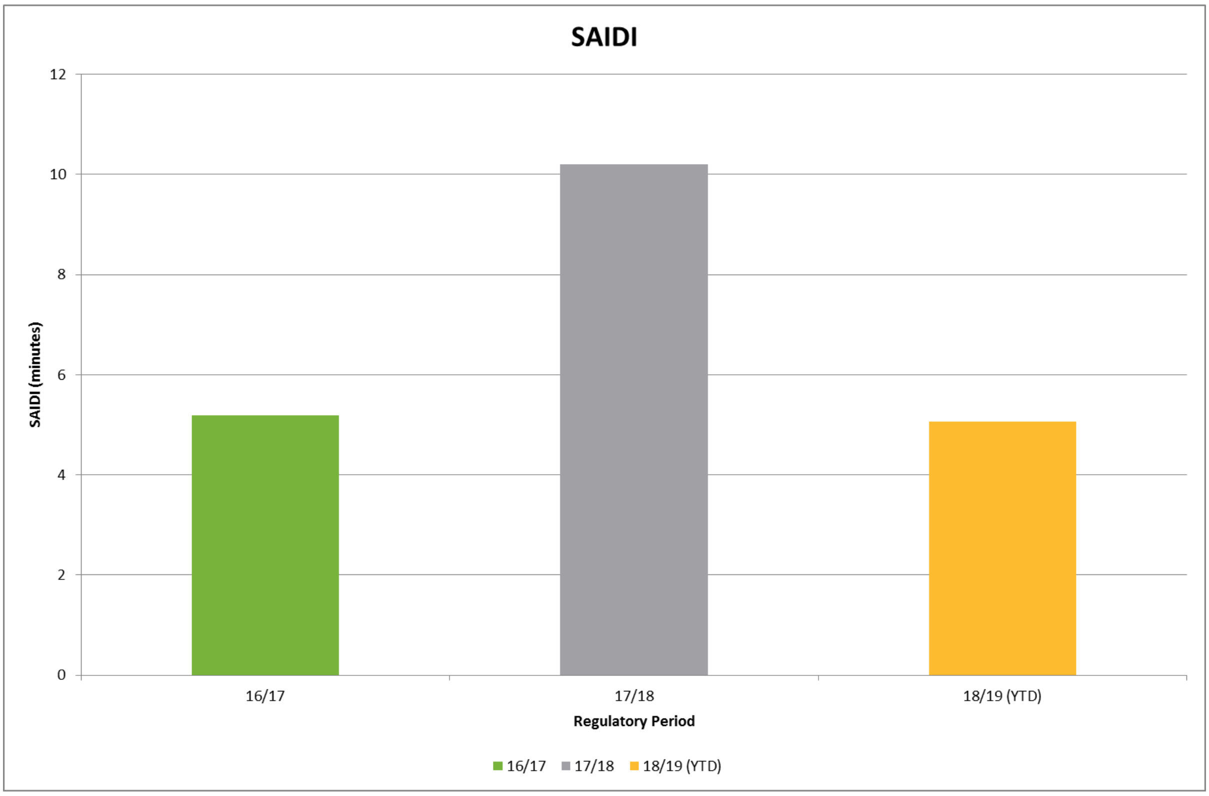


Figure 6-16 SAIDI Impact of Underground Equipment Failure as the Fault cause

The cause of the increase in cable faults is damage to joints and cable sheaths could have been caused by the November 2016 earthquake, leading to moisture ingress and failure during the winter of 2017. There is a correlation in the location of ground shaking during the November 2016 earthquake and the location of cable faults during 2017/18, as shown in Figure 6-17. This mirrors Orion's experience of an initial increase in failures in the aftermath of the Christchurch earthquakes, followed by a gradual return to historical failure rates[27]. While the rate of 11 kV cable faults declined in 2018/19, low voltage cables have continued to show elevated failure rates.

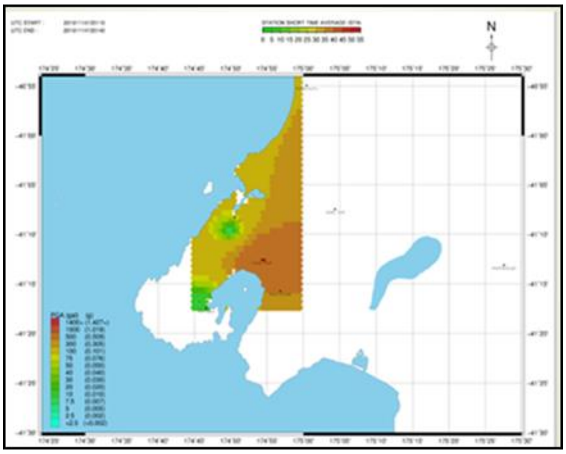


Figure 6-17 11 kV Cable Faults from 2017/18 vs. Kaikoura Earthquake Ground Shaking Intensity[28]

[27] Orion Asset Management Plan 2018-2028, Section 4.11.

[28] Ground shaking intensity map supplied by GNS. Yellow areas indicate strong ground shaking.

Specific controls for underground events are:

- A cable test programme focussing on high risk cable sections including Lower Hutt area with elevated fault numbers in 2017/18;
- Cost benefit analysis used to determine whether to replace or repair cables following faults; and
- Asset health and criticality analysis used to assess the risk of 33kV cables which has also been extended to 11 kV cables.

6.5.1.6 Third Party Incidents

Third party incidents contributed 20% or 10.7 minutes and 31% or 8.3 minutes of the total SAIDI incurred in 2017/18 and 2018/19 YTD, respectively. This is a significant increase compared to the average previous contributions of 3.8 minutes and the allowance in the target based on the reference period average of 4.8 minutes. The primary contributor to third party incidents was car versus pole events.

The UFB network project which had a significant impact on the number of third party strikes in 2015/16 and 2016/17, has reduced significantly. This is due to the intensive engagement that WELL undertook with UFB contractors to ensure that their workers are competent to work in proximity to the network and the agreements arranged with UFB providers to allow provisioning from the WELL overhead network rather than underground. Similarly, third party incidents due to landowners felling trees have decreased.

The breakdown of the number of events and SAIDI impact are shown in Figures 6-18 and 6-19.

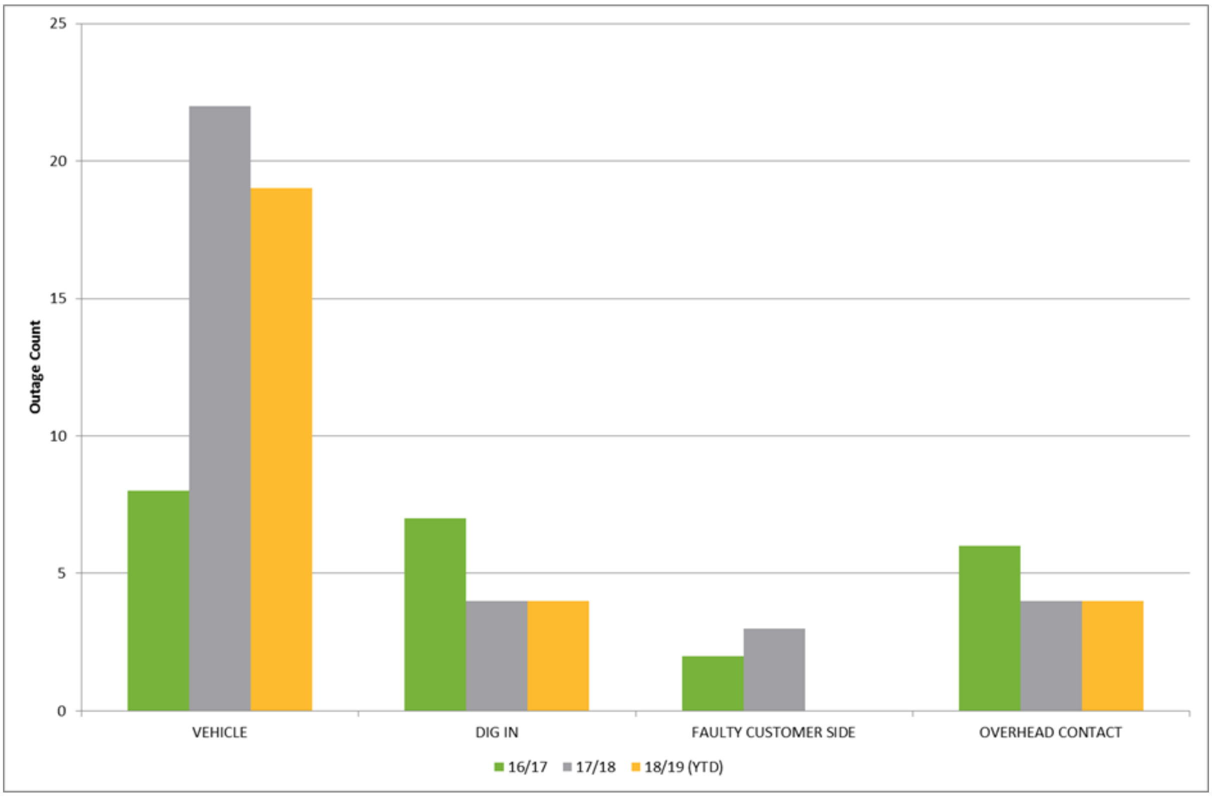


Figure 6-18 Outage Count of Third Party Incidents as the Fault Cause

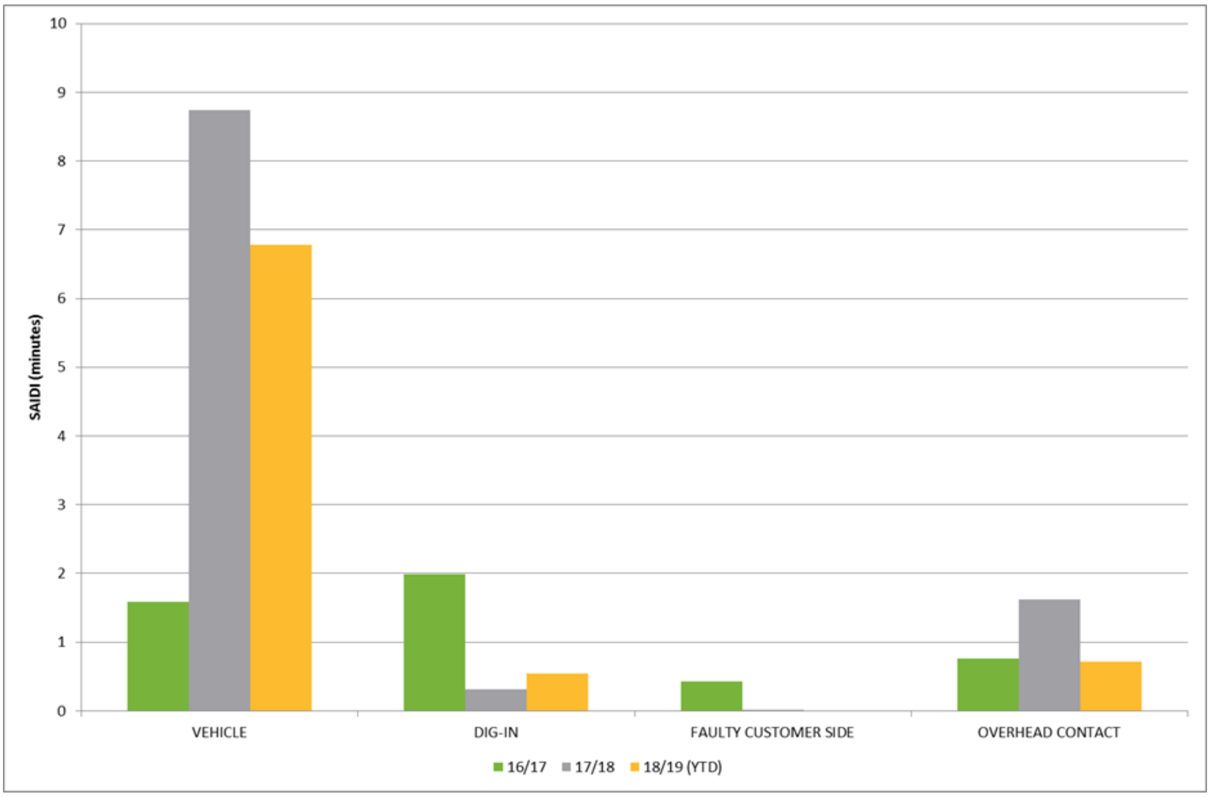


Figure 6-19 SAIDI Impact of Third Party Incidents as the Fault Cause

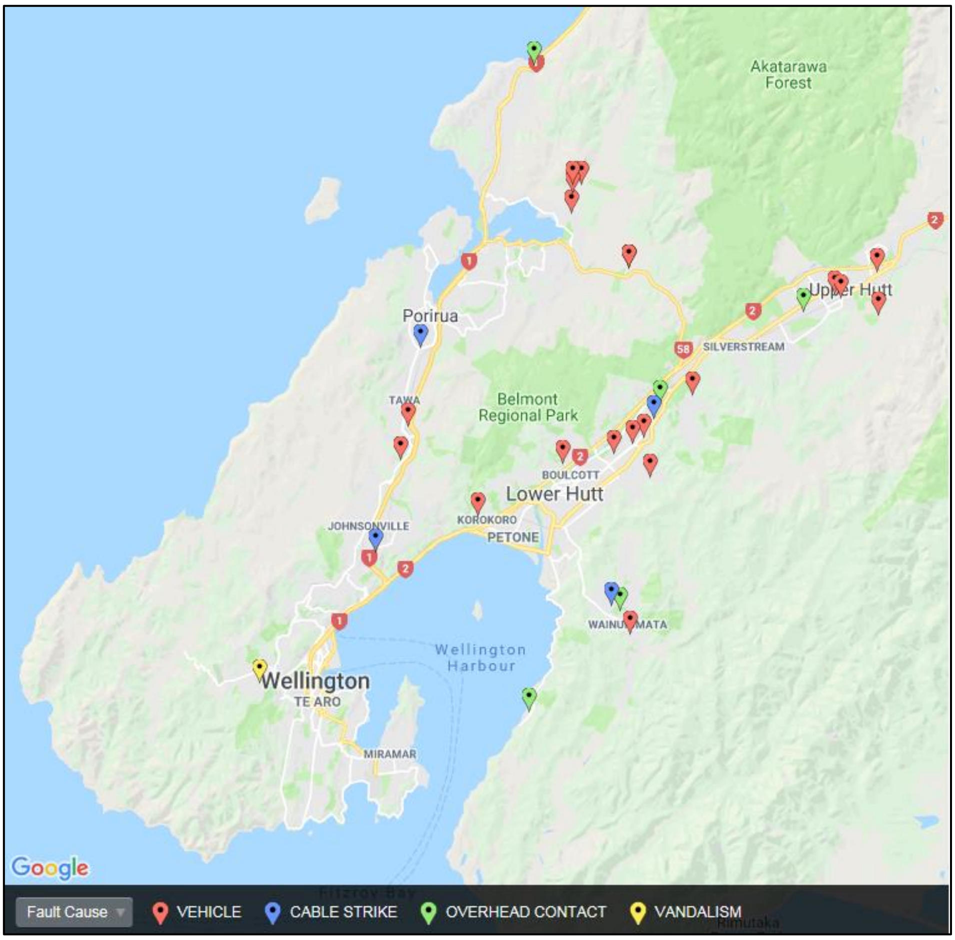


Figure 6-20 Third Party Events for 2018/19 (YTD)

Specific controls for car versus pole events are:

- Increasing the visibility of poles in identified higher risk areas. Existing poles near intersections have reflectors and white paint at the bottom of the pole, and all new poles installed beside roads are fitted with reflectors; and
- Considering relocation of poles when they are being replaced.

WELL has deployed a number of safety campaigns targeting third party contractors working around the network assets. These include:

- Engaging those involved with the UFB roll out programme;
- Targeting trades and contractors with radio advertising ("Look Up, Look Out"); and
- Continuing to participate in the 'Before U Dig' programme which provides free plans and cable mark-outs to third parties during the planning process and prior to field excavation.

Figure 6-21 Fault Cause – Car versus Pole

6.5.1.7 Lightning and Animal Fault Causes

Outages due to lightning on 11kV assets are usually the result of failure of overhead transformers caused by the strike. Extreme lightning events do not occur often in the Wellington region.

Outages due to animals are caused by birds and possums contacting the 11kV overhead lines. To reduce the risk posed by possums WELL uses possum guards (a 600 mm tall metal sheet wrapped around the mid-section of the pole) in rural areas.

6.5.1.8 Substation Equipment

Substation equipment related outages remain well controlled by WELL's switchgear replacement programme, described further in Chapter 7.

6.5.1.9 Other Significant Controls

WELL also has implemented a number of other generic controls that apply across all categories:

- Mitigating, where practicable, the impact of severe storms by using line sectionalisers, line fault indicators and reclosers, and by employing well-practiced emergency restoration plans;
- Analysing all significant outages (over 0.45 SAIDI minutes or 0.02 SAIDI interruptions) to identify root causes and recommendations to prevent recurrence;
- Monitoring trends in outages causes and other asset failures to identify changes in maintenance practices and to confirm assets to be upgraded;
- Monitoring of field response and repair times for major faults to identify causes of prolonged outages and develop strategies to improve restoration times;
- Further refinement of the targets to reflect consumer segments (for example, Wellington CBD requires a higher level of security than rural consumers); and
- Extending risk based analysis in asset strategies to cover conductors and underground cables.

6.5.2 External Reviews

A period of extreme weather events led to WELL's non-compliance with the Quality Path in both 2012/13 and 2013/14. This non-compliance prompted the Commission to engage Strata Consulting to review WELL's asset management practices. Strata included recommendations from the review that it considered, if applied by WELL, would be likely to improve the probability of achieving and sustaining reliability performance within the quality standards in the future. These recommendations have been completed as detailed in previous AMPs.

Following the exceedance of reliability limits in 2017/18, the 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 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 have been turned into actions that are being tracked by the Board.

6.6 Worst Performing Feeder Programme

WELL undertakes line refurbishment on sections of network due to condition or performance. These projects are determined from the analysis of the worst performing feeders.

Identification of worst performing feeders is based on five factors:

- SAIDI – if the feeder has had an annual SAIDI greater than or equal to 0.50 minutes;
- SAIFI – if the feeder has had an annual SAIFI greater than or equal to 0.01;
- Number of interruptions – if the feeder has greater than or equal to 2 interruptions;
- If the feeder outages have accumulated an annual reliability cost of over $100k; and

- If the feeder performance has deteriorated significantly since the previous period in any of the above four factors.

Faults on these worst performing 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.

A limitation of the programme is the degree to which the worst performing feeders vary from year to year, so while it will produce a general improvement over time, it cannot prevent a one-off high impact failure on a feeder with no history of poor performance.

It also takes time for the benefits of these programmes to become apparent in reliability statistics. The reliability programmes in place for the 2016/17 Worst Performing Feeders are identified in Table 6-3, while the benefits of those programmes are shown in Figures 6-22 and 6-23 of the improvement in reliability of the feeders concerned. The programmes for the 2017/18 worst performing feeders are currently in progress, with their benefits expected to become visible from 2019/20 onwards.

Worst Performing Feeders 2016/17	Reliability Programme
Maidstone 10	Vegetation management
Melling 10	Line refurbishment
Ngauranga 4	Line refurbishment
Plimmerton 8	Vegetation management
Brown Owl 5	Line refurbishment
Haywards 2722	Line refurbishment
Tawa 11	Vegetation management
Plimmerton 11	Line refurbishment
Ngauranga 7	Line refurbishment
Brown Owl 3	Vegetation management

Table 6-3 Reliability Programmes for the 2016/17 Worst Performing Feeders

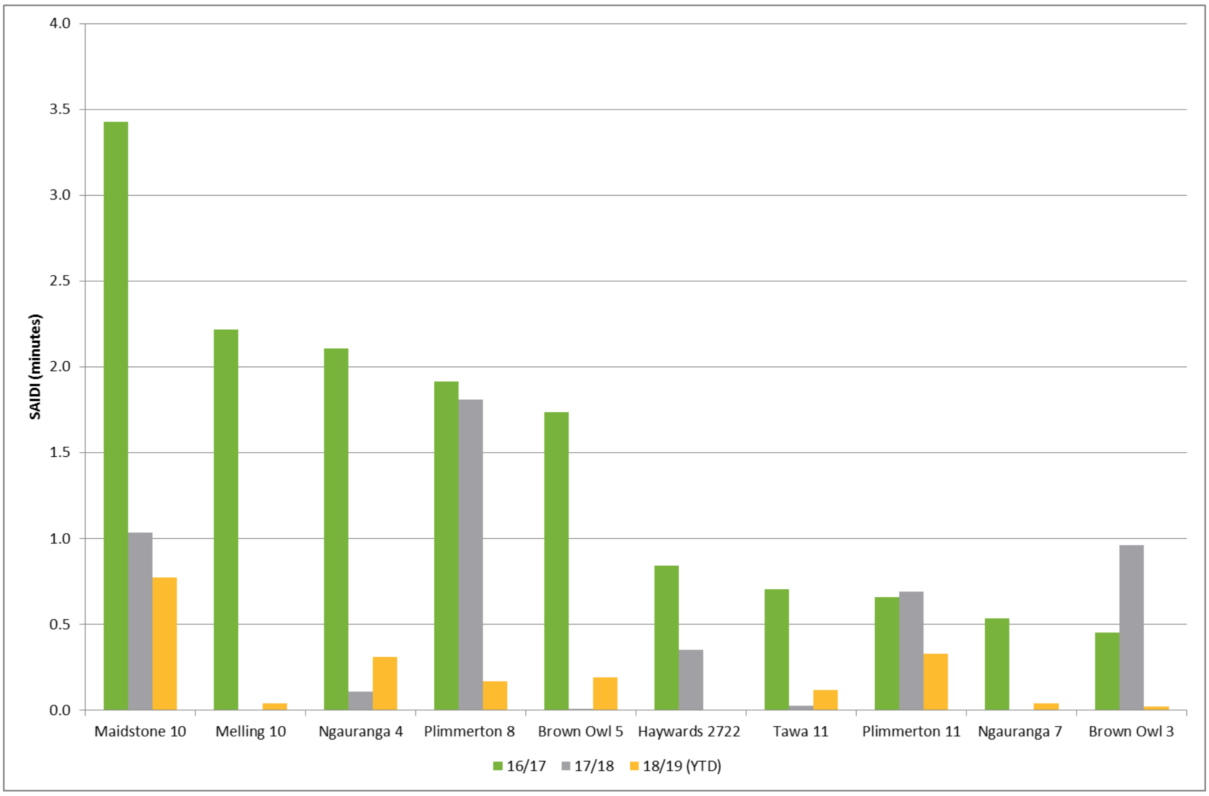


Figure 6-22 Improvement of the 2016/17 Worst Performing Feeders by SAIDI

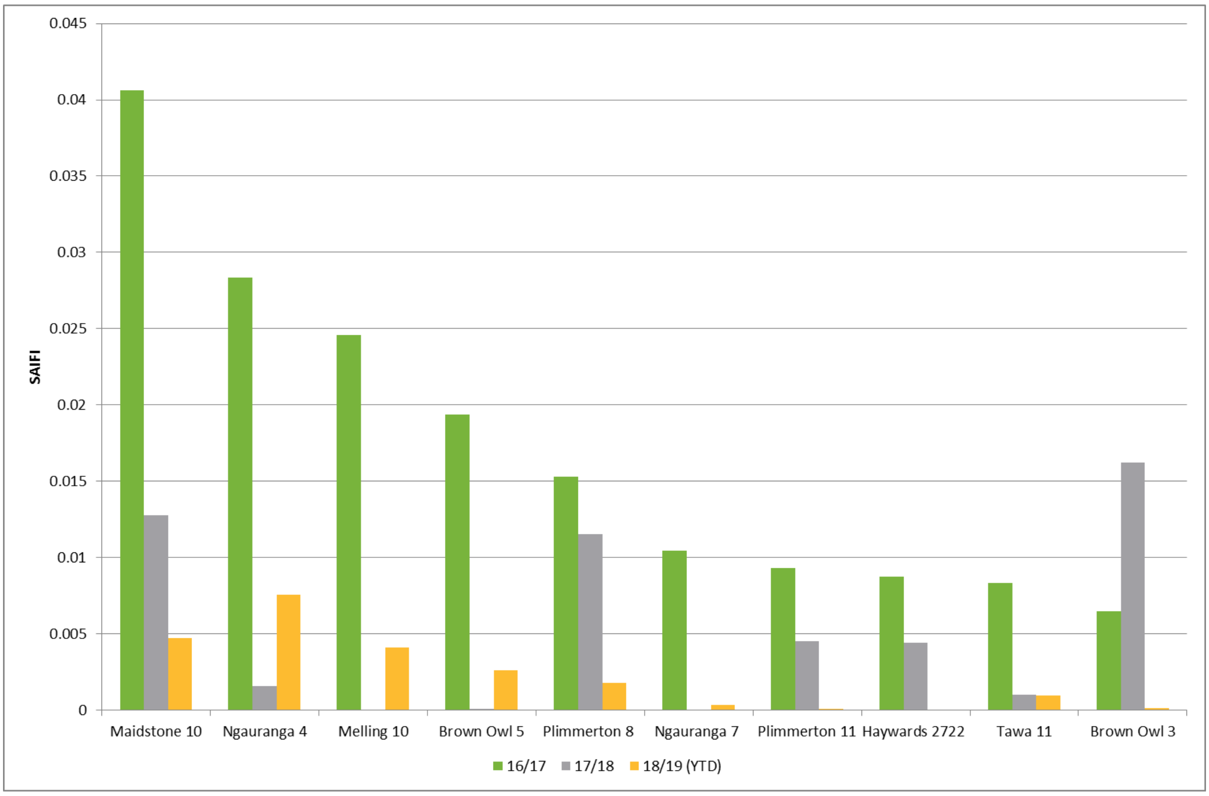


Figure 6-23 Improvement of the 2016/17 Worst Performing Feeders by SAIFI

6.7 Reliability Contribution by Council Area

Figures 6-24 and 6-25 show the SAIDI and SAIFI contributions from each network area to the overall WELL regional performance figures. One notable fact has been the increase in SAIDI and SAIFI, particularly in the Lower Hutt area, due mainly to the larger amounts of de-energised work as a result of the HSW Act (discussed in Section 6.1).

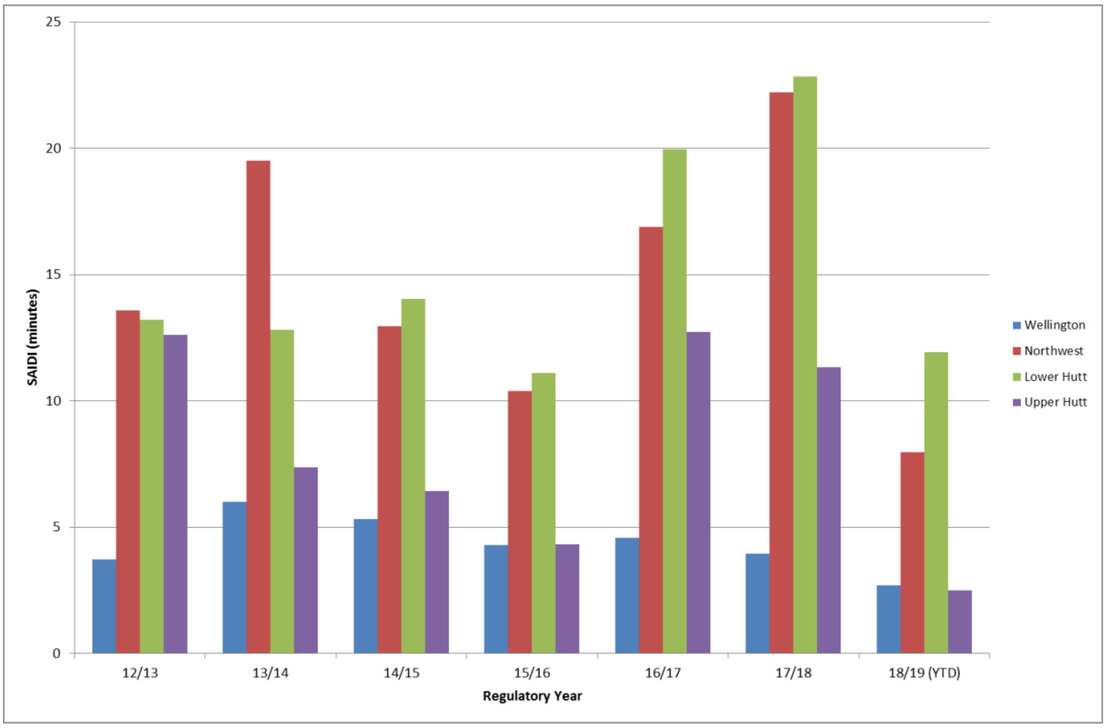


Figure 6-24 SAIDI Contribution by Area (as at February 2019)

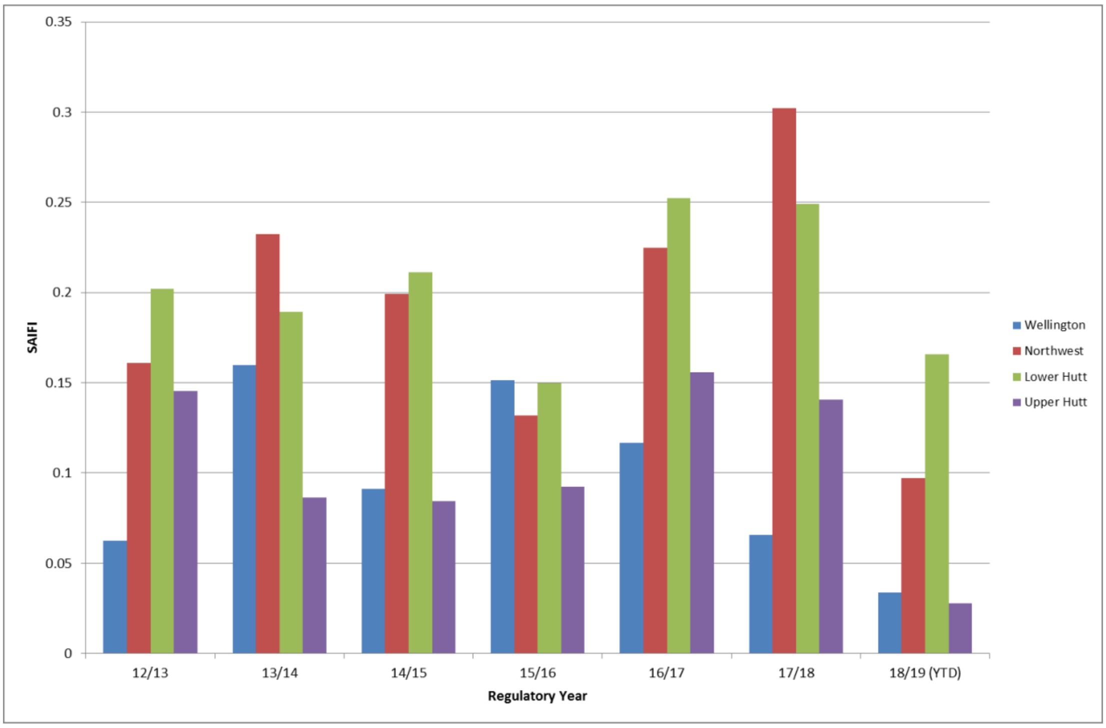


Figure 6-25 SAIFI Contribution by Area (as at February 2019)

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;
- Stage-of-life and asset health 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
Sub Transmission	Sub transmission Cables	7.5.1	km	138
	Sub transmission 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	1,674
	Streetlight Lines	7.5.3.3	km	810
	Distribution and LV Poles	7.5.3.1	number	39,561
Distribution and LV Cables	Distribution and LV Cables	7.5.4	km	2,875
	Streetlight Cables	7.5.4	km	1,105
Distribution Substations and Transformers	Distribution Transformers	7.5.5.1	number	4,399
	Distribution Substations	7.5.5	number	3,702

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Distribution Switchgear	Distribution Circuit Breakers	7.5.6	number	1,279
	Distribution Reclosers	7.5.7.1	number	16
	Distribution Switchgear - Overhead	7.5.7.2	number	2,576
	Distribution Switchgear - Ground Mounted/Ring Main Units	7.5.6	number	2,567
Other Network Assets	Low Voltage Pits, Pillars and Cabinets	7.5.6.1	number	12,250
	Protection Relays	7.5.8.2	number	1,405
	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 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 trended degradation of condition that may occur across a fleet. Corrective maintenance tasks identified as a result of preventative maintenance are prioritised for repair according to severity and consequential risk to safety and network performance.

Standardised designs are used for high volume assets, including overhead and underground construction, 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 sub transmission cables and zone substation assets are designed to meet the specific needs of the project, however must still meet the requirements of relevant network standards.

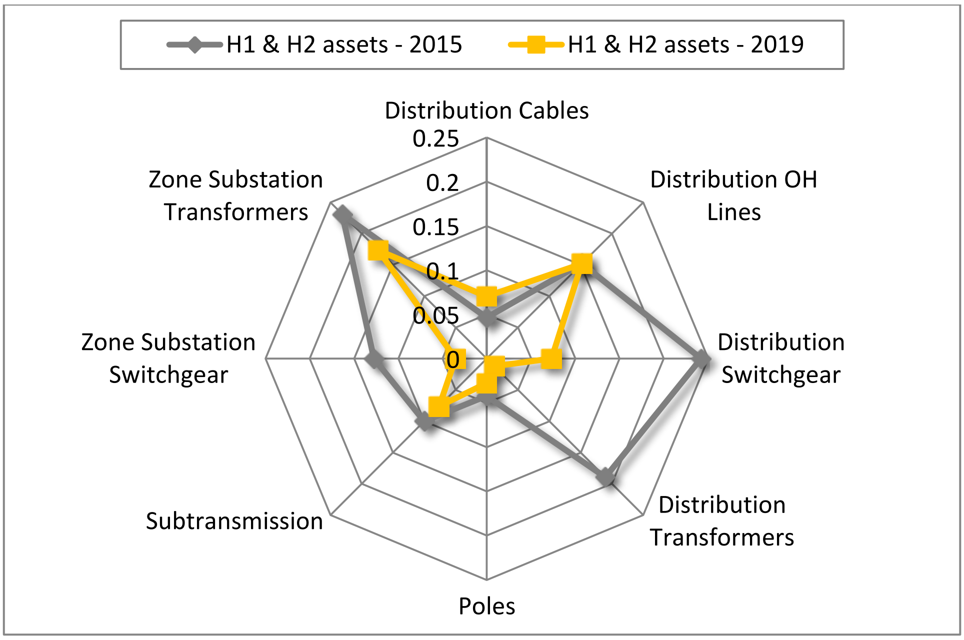
Electricity distribution assets have a long but finite life expectancy and eventually require replacement. Premature asset replacement is costly as the service potential of the replaced asset is not fully utilised. Equally, replacing assets too late can increase the risk of safety incidences and service interruptions for 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 an insight into the condition and maintenance of each class with an overview of maintenance programmes and renewal and refurbishment programmes.

7.3 Asset Health Analysis

WELL makes use of 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 (new) to H1 (end of life). The overall Asset Health Indicator (AHI) is determined by its worst health index, further reduced by any indices scoring less than H4.

The results of WELL's AHI are displayed below and show that since 2015 WELL has reduced the number of assets in the H1 & H2 categories for most asset fleets. It must be noted that over this same period, the methodologies to calculate asset health have changed slightly and that data accuracy has also improved.



Asset Health Analysis does not rely on factors having subjective weightings and does not take into account asset criticality or consequence of failure. WELL has developed an Asset Criticality Indicator (ACI) 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. As an example, the health-criticality matrix for power transformers on the WELL network is shown in Figure7-1 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			
	1.5				2			
Asset Health	2.0							
	2.5			5	20			1
	3.0			4	7		4	1
	4.0			1	2		2	2
Best Health	5.0							

Figure 7-1 Health-Criticality Matrix (Power Transformers example)

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

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

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

- Sub transmission cables;
- Zone substation power transformers and tap changers;
- Zone substation switchboards and circuit breakers;
- Poles;
- Distribution transformers;
- Ground-mounted distribution switchgear;

- Distribution cables; and
- Distribution overhead lines.

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 Field Services Agreement. 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. Under the regulations, tree owners are responsible for maintaining their vegetation to a safe clearance distance. There is a risk that this maintenance does not occur and vegetation related outages may start to increase if tree owners neglect their obligations under the Regulations.

7.4.2 Maintenance Categories

Maintenance is categorised into the following areas:

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

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

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

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

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

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

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

The forecast maintenance expenditure for 2019-2029 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:

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

7.5.1 Sub transmission (Cables)

Fleet Overview

WELL owns approximately 138 km of sub transmission cables operating at 33 kV. These comprise 50 circuits connecting Transpower GXPs to WELL's zone substations. Approximately 32 km of sub transmission 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 sub transmission circuits supplying Ira Street zone substation are oil-filled PIAS (paper insulated aluminium sheath) cables rated for 110 kV but operating at 33 kV. Even though WELL has a number of mature cables in its fleet, all cables are monitored via weekly inspections and monitoring of cable pressures and fluid leakages. Each individual cable 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 7-2.

Construction	Design voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33 kV	30%	42km
Paper Insulated, Gas Pressurised	33 kV	33%	46km
Paper Insulated	33 kV	7%	9km
XLPE Insulated	33 kV	23%	32km
Paper Insulated, Oil Pressurised	110 kV	7%	9km
Total			**138km**

Table 7-2 Summary of Sub transmission Cables

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

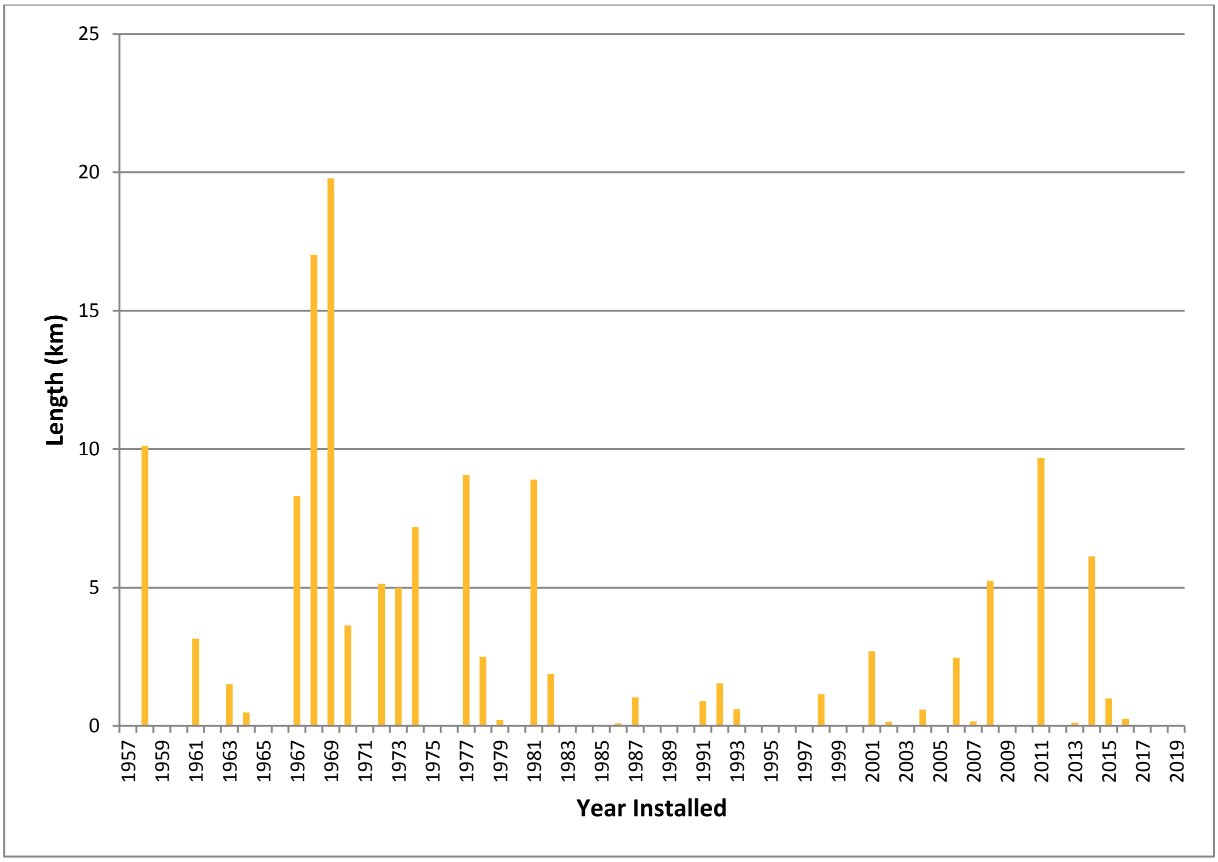


Figure 7-2 Age Profile of Sub transmission Cables

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on sub transmission 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
Sub transmission - cable gas / oil injection equipment inspection	Inspection and minor maintenance of equipment in substations, kiosks and underground chambers.	6 monthly
Sub transmission - regular patrol	Patrol of cable route; replace missing or damaged cable markers.	Weekly

Table 7-3 Inspection and Routine Maintenance Schedule for Sub transmission Cables

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

When fluid-filled cables develop a leak, they can usually be dug up and repaired without having to cut the cable. However, when a more serious electrical fault occurs, a new section of cable will be necessary. On some occasions transition joints are made to join the pressurised cables to sections of XLPE cable. These joints are relatively expensive at around $100,000 each, meaning that to replace even short sections of cable will cost a minimum of $250,000, making it uneconomic to have a large number of such joints in a single cable. The outcome of this is that where a cable is located in an environment where damage is likely to occur, it is more economical to install a long length of replacement XLPE cable than several short lengths.

One of the key tests is the sheath test, which indicates whether there is damage to the outer sheath and gives an early indication of situations where corrosion or further damage (leading to leaks) may occur, as well as proving the integrity of the earth return path.

Objective condition assessment on cables with fluid pressurisation is difficult and quite limited, as a number of assessment techniques, including partial discharge testing, are not applicable to these types of cables. The main mode of failure of these cables is stress on the joints and resulting failure, as well as sheath failures allowing 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 sub transmission cables are outlined in Table 7-4.

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 damaged sections of gas filled cables with non-pressurised XLPE cables where necessary.
Emergency Overhead Line Spares	WELL is investing in the design of alternative overhead line routes for all fluid filled sub transmission cables to prepare for the possibility of significant damage post a major earthquake. WELL is procuring enough spares to construct 19km of emergency overhead lines. This is part of the approved SCPP programme discussed in detail in Section11.

Table 7-4 Spares for Sub transmission Cables[29]

Cable Condition and Failure Modes

Gas-filled cables

Gas-filled HV cables have been in use internationally since the 1940s and are still in service in many utilities in New Zealand and Australia. They have proven to perform well when they are installed in benign environments that are not prone to disturbance or damage. WELL, however, has many of its gas-filled cables installed under busy roads in urban environments and through structures such as bridges. Vibration from traffic has been identified as a contributing factor to some mechanical failures. This requires close monitoring of cable performance to manage any deterioration and consequent reduction in levels of service. Some of these cables in particular have been repaired numerous times as a result of third party damage or after gas leaks have been found.

The Evans Bay 1 cable is being regularly topped up with gas throughout the year. A maintenance task has been created for the location, identification and repair of the gas leak on this cable which will be done in 2019. The rate of leakage on gas cables throughout 2018 has remained constant with no significant trends of increasing leakage identified.

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.

A large fluid leak occurred on the Titahi Bay B cable in 2018 which is of 33kV construction but is operated at 11kV. The leak was found to be in the pipework of the hydraulic system in January 2019 and repaired. Levels are now back to normal and the cable pressure will continue to be monitored.

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

Paper and Polymeric Cables

Approximately 30% of WELL's sub transmission cable has solid insulation of either oil-impregnated paper or XLPE. These cables are relatively new compared to the fluid-filled installations.

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

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

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

Cable Strikes

WELL, like most lines businesses and other utilities, experiences a number of third party strikes on its underground assets each year. These pose a serious risk to health and safety, impact network performance, and incur a large cost to repair. Unfortunately not all of these third party incidents are identified and reported at the time of the incident, which may lead to future safety and network reliability problems.

To minimise the number of third party strikes, WELL uses the B4U-DIG programme to facilitate the provision of plans to contractors working in the area, with Northpower providing cable mark outs and stand-overs where appropriate. WELL has a focused education campaign for contractors working for large utility companies and local authorities with presentations educating them on the importance of cable location and excavation practices.

In addition, cable maintenance staff patrol the routes of all sub transmission circuits on a weekly basis and note any activities that may impact upon underground services. Where necessary, third party contractors are reminded of the risks associated with working around underground cables.

The B4U-DIG programme has shown positive results by reducing the number of cable strikes experienced per annum on HV cables, but an increasingly worrying factor has been the number of cable strikes experienced on LV cable. This has resulted in further work being undertaken in 2019 to engage with third party civil contractors via the B4U-DIG programme.

Renewal and Refurbishment

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

Sub transmission Asset Health and Criticality Analysis

The Asset Health Analysis considers the attributes of each sub transmission cable circuit for both health and criticality categories, as shown in Table 7-5.

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

Table 7-5 Categories and Attributes for Sub transmission Cable Circuits

Considering the above attributes for each circuit gives the health-criticality matrix shown in Figure 7-3, 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.

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

Figure 7-3 Sub transmission Cable Circuit Health-Criticality Matrix

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

Sub transmission Circuit	Primary Type	AHI	ACI	Rating
Gracefield A & B	PILC	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 Sub transmission Cable Circuits

Outcome of the Asset Health Analysis

The Asset Health Analysis shows that fluid-filled cables rate lower than modern cables on a number of categories, primarily driven by the cost and availability of parts and workforce skills. The highest possible health index for a fluid-filled cable under the AHI method is 2.8, so fluid-filled cables have a high health based priority for replacement.

The highest priority sub transmission cable circuits, and significant changes since the 2018 AMP, are discussed below.

University

The gas-filled University cables were largely replaced, 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.

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

Korokoro

The Gracefield to Korokoro A cable was reported to have numerous sheath faults and was originally programmed for location, identification and repair in 2018. Due to the stability of the fluid pressures in the cable (supported by AHI & ACI analysis), this work has since been deferred to 2020 due to the Evans Bay gas leak which is the next priority to be completed.

Evans Bay

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

Analysis during 2015 has shown that the issues at Evans Bay are specifically related to Circuit 1. This circuit has a much higher rate of gas leakage than Circuit 2, resulting in a reassessment of the Circuit 2 AHI. A maintenance task has been created for the location, identification and repair of the gas leak on this cable which was originally scheduled to occur in 2018 but has been deferred to 2019 due to the escalation of the fluid leak on the Titahi Bay B cable in 2018.

Johnsonville

Analysis during 2015 showed that the oil-filled cables on the Johnsonville A circuit were demonstrating a small but consistent rate of fluid leakage. In 2016 this leak was identified as occurring within an area immediately outside the substation at a transition joint which was fixed in 2017. The joint has been monitored and there have been no further leaks. However, this is the second recent leak in these cables and a complete cable replacement may be undertaken towards the end of the planning period.

Tawa

Condition monitoring during 2017 showed that the fluid-filled cable on the Tawa A circuit started leaking in August. 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 since the 2017 repair.

Titahi Bay

In early 2018 it was identified that an fluid-filled cable on the Titahi Bay circuit was demonstrating fluid leakage. After significant effort the leak was located and repaired in January 2019. The leak was found to have occurred on the pipe work of the hydraulic system. The cable pressure will continue to be monitored.

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 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 2020 for capacity reasons.

<u>Expenditure Summary for Sub transmission Cables</u>

Table 7-7 details the expected expenditure on sub transmission cables by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Cable Replacement	-	-	-	-		3,000	2,500	1,500	1,500	-
Reactive Capital Expenditure	350	350	350	350	350	350	350	350	350	350
Capital Expenditure Total	**350**	**350**	**350**	**350**	**350**	**3,350**	**2,850**	**1,850**	**1,850**	**350**
Preventative Maintenance	116	116	116	116	116	114	114	114	114	114
Asset Renewal and Replacement Opex	323	345	366	390	413	432	443	307	400	400
Operational Expenditure Total	**439**	**461**	**482**	**506**	**529**	**546**	**557**	**421**	**514**	**514**

Table 7-7 Expenditure on Sub transmission 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. Each power transformer is individually monitored and modelled via WELL's Asset Health & Criticality system. The age profile for zone substation transformers is shown in Figure 7-4.

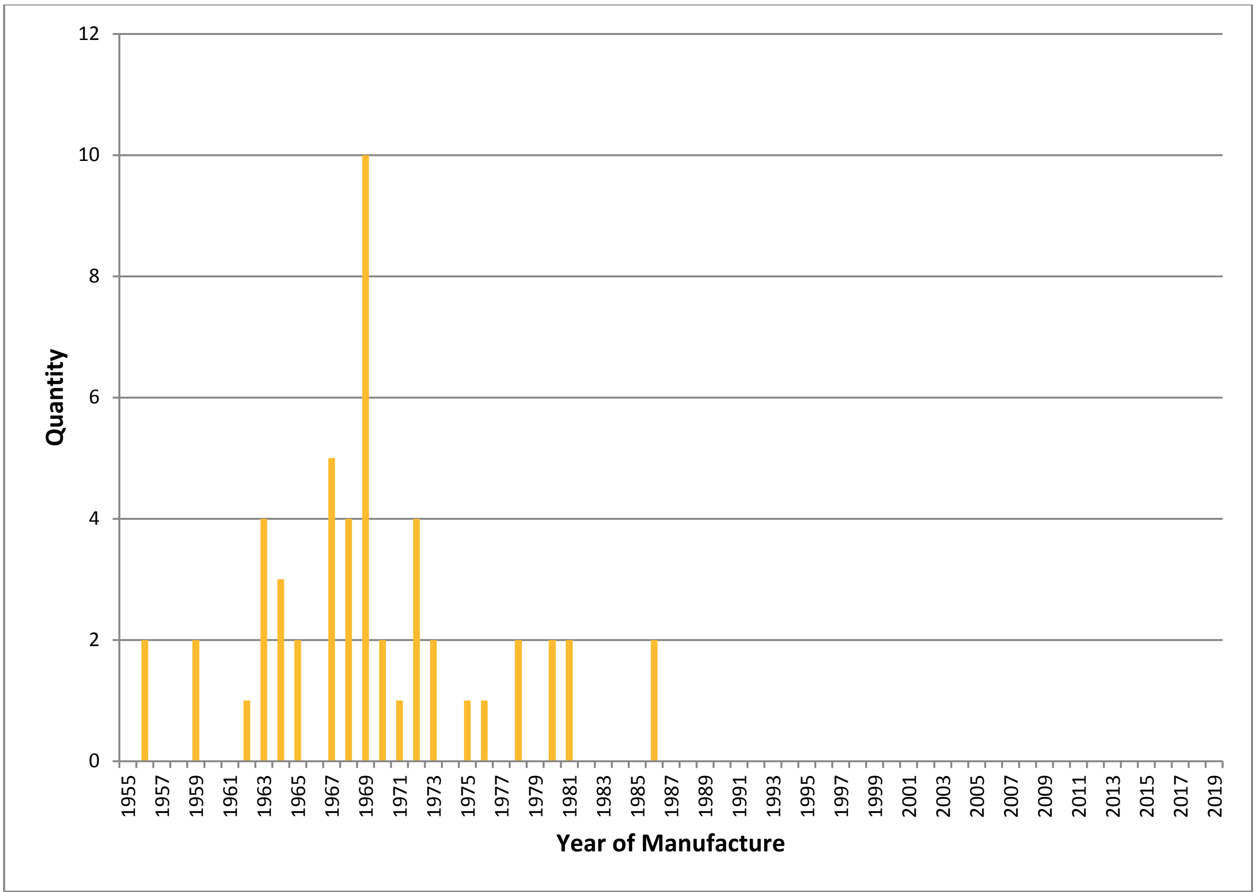


Figure 7-4 Age Profile of Zone Substation Transformers

The mean age of the transformer fleet is 50 years.

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[30].	4 yearly

Table 7-8 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 7-9.

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 7-9 Spares Held for Zone Substation Transformers

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

Figure 7-5 Strategic Spare Power Transformer, Pre (Left) & Post (Right) Refurbishment

Transformer Condition

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

A recent discovery has been the deterioration of barrier boards on Fuller tap changers which 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 whilst alternate retrofit and repair options are being investigated.

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

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.

Also in 2017 it was identified that the Wanuiomata T2 had started to show signs of corrosion on the radiators. A spare set of radiators has been sourced and purchased and a project has been raised to retrofit this radiator onto the Wanuiomata transformer during 2019.

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 three[31] zone substations; and
- Ongoing transformer refurbishment costs.

Based on asset health and criticality, three zone substation transformers are planned for replacement during the period 2019 to 2029. All factors considered in the replacement decision-making process are covered in the Asset Health Analysis described below.

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.

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

The Asset Health Analysis considers the attributes of each power transformer for both health and criticality categories, as shown in Table 7-10.

Category	Attributes
Health	Degree of Polymerisation
Health	Bushing Condition
Health	Mechanical Integrity (i.e. SFRA testing)[32]
Health	Insulation System Condition
Health	Known Type or Design Issues
Health	Safety Features
Health	Availability of Parts for OLTC Maintenance
Health	Noise
Health	Workforce Skills
Criticality	Primary Load Type (CBD, Industrial, Residential)
Criticality	Number of Customers Served
Criticality	Bus Configuration at Zone Substation
Criticality	Availability of 11 kV Back feeds

[31] There are 2 transformers catered for at Evans Bay substation for asset health reasons.
There is 1 transformer catered for at Mana substation for asset health reasons.
There are also 2 transformers catered for at Ngauranga substation for capacity reasons (See Section 8).

[32] Transformer SFRA testing is not currently undertaken by WELL.

Category	Attributes
Criticality	Installation Issues, e.g. access restrictions

Table 7-10 Categories and Attributes for Power Transformers

Applying the above factors to each transformer gives the health-criticality matrix shown in Figure 7-6, with individual transformer scores and ratings being presented in Table 7-11.

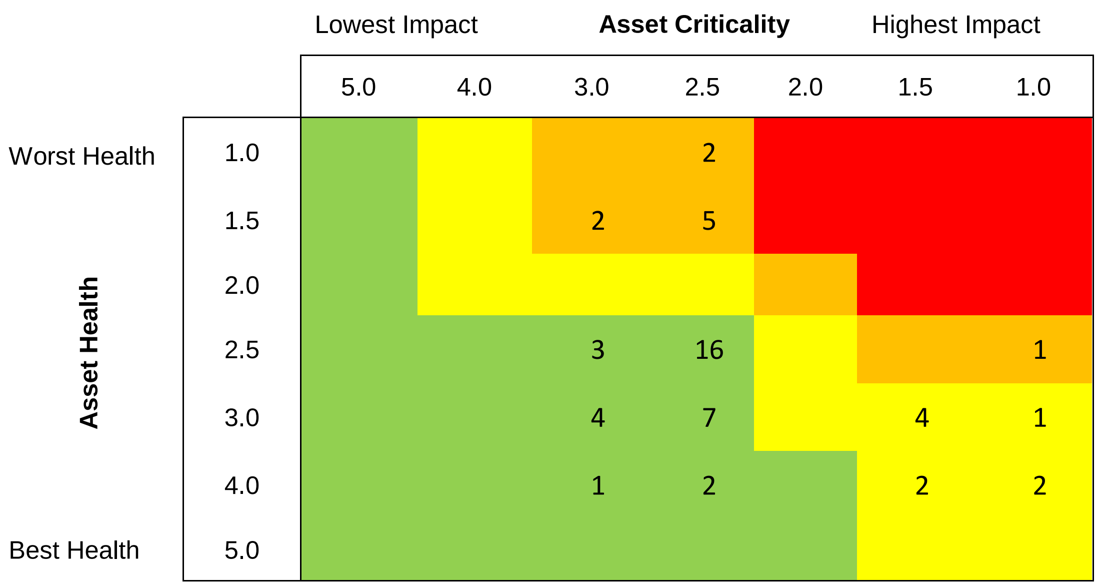


Figure 7-6 Power Transformer Health-Criticality Matrix

Transformer	Substation	AHI	ACI	Rating
Evans Bay T1	Evans Bay	1.2	2.8	
Evans Bay T2	Evans Bay	1.2	2.8	
Mana	Mana-Plimmerton	1.9	2.9	
Frederick Street T1	Frederick Street	2.9	1.3	
Frederick Street T2	Frederick Street	3.0	1.3	
Palm Grove T1 & T2	Palm Grove	3.0	1.6	
University T1	University	3.0	1.7	
Moore Street T2	Moore Street	3.0	1.8	
Terrace T1 & T2	Terrace	4.0	1.3	
University T2	University	4.0	1.7	
Moore Street T1	Moore Street	4.0	1.8	
Brown Owl A	Brown Owl	2.9	3.0	
Brown Owl B	Brown Owl	2.9	3.0	
Gracefield A	Gracefield	2.8	2.9	
Gracefield B	Gracefield	2.9	2.9	
Hataitai T1 & T2	Hataitai	2.9	2.8	
Ira Street T1	Ira Street	3.0	2.9	
Ira Street T2	Ira Street	4.0	2.9	
Johnsonville A & B	Johnsonville	2.8	2.9	
Karori T1	Karori	2.8	2.9	
Karori T2	Karori	2.9	2.9	
Kenepuru A	Kenepuru	4.0	2.9	
Kenepuru B	Kenepuru	3.0	2.9	
Korokoro A	Korokoro	2.9	2.9	
Korokoro B	Korokoro	3.0	2.9	
Maidstone A	Maidstone	3.0	2.9	

Transformer	Substation	AHI	ACI	Rating
Maidstone B	Maidstone	2.9	2.9	
Naenae T1 & T2	Naenae	3.0	3.0	
Ngauranga A	Ngauranga	2.9	2.8	
Ngauranga B	Ngauranga	3.0	2.8	
Plimmerton	Mana-Plimmerton	2.8	2.9	
Porirua A & B	Porirua	2.9	2.9	
Seaview A	Seaview	2.7	2.9	
Seaview B	Seaview	2.9	2.9	
Tawa A	Tawa	1.7	2.9	
Tawa B	Tawa	1.6	2.9	
Trentham A & B	Trentham	1.8	3.0	
Waikowhai T1	Waikowhai	1.7	2.9	
Waikowhai T2	Waikowhai	1.7	2.9	
Wainuiomata A	Wainuiomata	3.0	3.0	
Wainuiomata B	Wainuiomata	4.0	3.0	
Waitangirua A	Waitangirua	3.0	3.0	
Waitangirua B	Waitangirua	2.9	3.0	
Waterloo A & B	Waterloo	3.0	2.9	

Table 7-11 Health-Criticality Scores for Power Transformers

Outcome of Asset Health and Criticality Analysis

Figure 7-7 shows the health of the power transformer fleet by unit age, against the theoretical trend in health over time. This shows that a large number of units are in better health than would be expected for their age. This is due to a number of factors, particularly the proportion of units located indoors and therefore less vulnerable to corrosion, and loading on transformers being kept below 50% for security reasons. Exceptions to this are noted below.

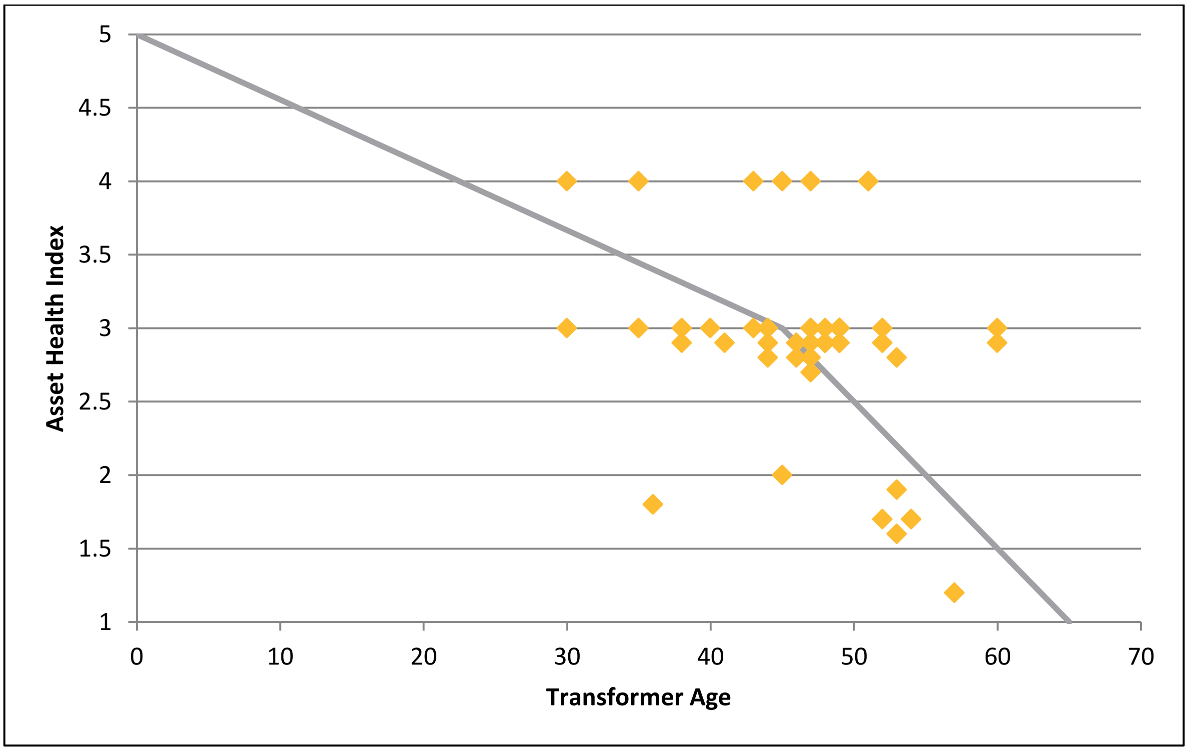


Figure 7-7 Asset Health vs Age for Power Transformers

Evans Bay

The transformers at Evans Bay were installed in 1959 and have the lowest health indices in the network. These transformers have experienced an increasing number of problems in recent years, mostly relating to the mechanical performance of the tap changer and excessive leaks due to deterioration of valves, flanges, gaskets and radiators. 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. A business case for the replacement of these transformers was approved in 2017 for replacement of these transformers by 2021. The feasibility study for the replacements has been completed and detailed designs are expected to begin in 2019.

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 DGA's on this unit show no concerning signs in terms of combustible gasses, carbon monoxide or carbon dioxide, however acidic content has been on a steady increase over the past years. The unit will be programmed for a paper sample to be removed for a detailed evaluation of remaining life and based on the results the unit will be programmed either for replacement or upgrade. Allowance for this replacement has been made in 2022/23 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. Section 8 also makes allowance for ring reinforcement from 2022 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 will be required at the end of the planning period, however as identified in Section 8, replacement of the transformers is planned for 2021 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 tap changers within these units are Ferranti D55's and so are not expected to have the same barrier board degeneration issues as the Fuller ones mentioned previously. The ethylene levels will continue to be monitored to determine the best course of action.

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 switching star contact rollers which were identified as worn.

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.

Expenditure Summary for Power Transformers

Table 7-12 details the expected expenditure on power transformers by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Evans Bay & Mana Transformer Replacements	500	2,000	1,000	2,000						
Capital Expenditure Total	**500**	**2,000**	**1,000**	**2,000**	**-**	**-**	**-**	**-**	**-**	**-**
Preventative Maintenance	105	95	105	100	105	95	105	125	100	100
Corrective Maintenance	24	25	27	29	31	32	35	30	30	30
Operational Expenditure Total	**129**	**120**	**132**	**129**	**136**	**127**	**140**	**155**	**130**	**130**

Table 7-12 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. The most common single type is Reyrolle Pacific type LMT circuit breakers. There are 368 circuit breakers located at zone substations on the WELL network. An age profile of these circuit breakers is shown in Figure 7-8.

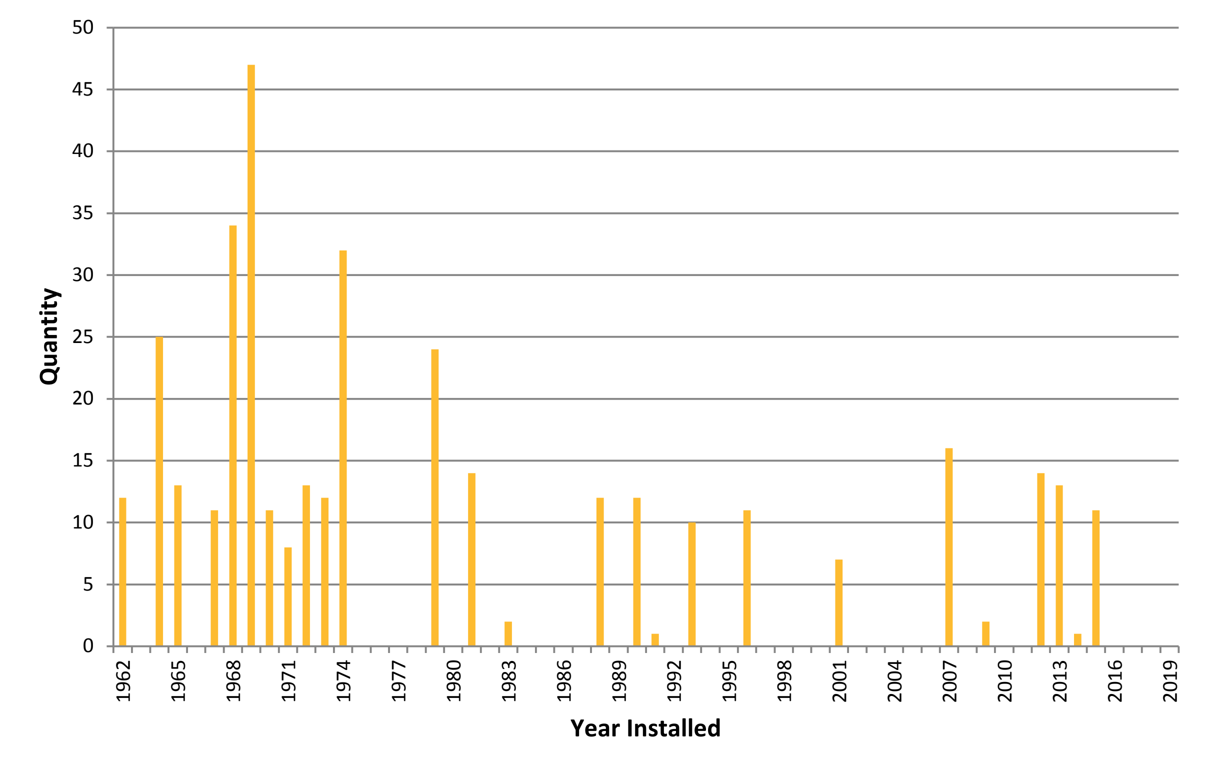


Figure 7-8 Age Profile for Zone Substation Circuit Breakers

The average age of zone substation circuit breakers in the Wellington Network is around 39 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 26 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 (as discussed in Chapter 8). Until then, a spare unit has been obtained from Transpower's Upper Hutt Substation when the outdoor breakers were removed as part of the outdoor/ indoor conversion project in 2017.

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

Table 7-13 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 7-14 Summary of Zone Substation Circuit Breakers by Manufacturer

Maintenance Activities

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

Activity	Description	Frequency
General Inspection of 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 7-15 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 7-16.

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 7-16 Spare Parts Held for Circuit Breakers

Switchgear Condition

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

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

The condition of zone substation switchboards is discussed in detail in the circuit breaker health-criticality analysis below.

Renewal and Refurbishment

Based on the condition assessment carried out as part of the preventative maintenance routine, assets are identified for replacement, or targeted inspection and maintenance programmes are put in place to manage risks until replacement is possible. A large number of older circuit breakers are still in service and are in excellent condition due to regular maintenance over their service life.

Condition, performance, ratings and operational history across the industry are considered when determining when a circuit breaker is replaced. Other drivers that influence the replacement decision include safety, criticality, operability and co-ordination with modern equipment.

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

Reyrolle Type C

Reyrolle Type C circuit breakers were installed between 1938 and the late 1960s and have reached the end of their effective service life. There are 13 units remaining in service at Gracefield zone substation and these are to be replaced by the end of 2019. The replacement Reyrolle LMVP switchgear was ordered in 2018.

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

All circuit breakers are surveyed with a handheld partial discharge meter as part of their routine annual general inspection, with zone substation circuit breakers receiving a full partial discharge survey annually from an 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.

<u>Circuit Breaker Asset Health and Criticality Analysis</u>

The Asset Health Analysis considers the attributes of each zone substation switchboard for both health and criticality categories, as shown in Table 7-17.

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

Table 7-17 Categories and Attributes for Zone Substation Switchboards

Considering the above attributes for each zone substation switchboard gives the health-criticality matrix shown in Figure 7-9, with individual switchboard scores and ratings being presented in Table 7-18.

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		1	
	2.0						1	1
	2.5			6	13		2	
	3.0				1			
	4.0				1			
Best Health	5.0				1		2	

Figure 7-9 Zone Substation Switchboard Health-Criticality Matrix

11 kV Switchboard	Model	AHI	ACI	Rating
Frederick Street	LM23T	2.0	1.3	
University	LMT	1.9	1.7	
Kaiwharawhara	LMVP	2.0	1.8	
Gracefield	C	1.2	2.9	
Mana	LM23T	1.8	2.9	
Moore Street	LM23T	2.9	1.8	
Nairn Street	LMT	2.9	1.8	
Johnsonville	LM23T	1.8	2.9	
Palm Grove	LMVP	5.0	1.6	
Terrace	NX-PLUS	5.0	1.8	
Brown Owl	LM23T	2.8	3.0	
Evans Bay	LMVP	3.0	2.8	
Hataitai	LM23T	2.9	2.8	
Ira Street	LM23T	2.9	2.9	
Karori	LMVP	5.0	2.9	
Kenepuru	LM23T	2.8	2.9	
Korokoro	LM23T	2.8	2.9	
Maidstone	LM23T	2.8	2.9	
Naenae	LM23T	2.9	3.0	
Ngauranga	LMT	2.9	2.8	
Petone	LM23T	2.9	2.9	
Plimmerton	LM23T	2.8	2.9	
Porirua	LM23T	2.9	2.9	
Seaview	LM23T	2.9	2.9	
Tawa	LM23T	2.9	2.9	
Titahi Bay	LMT	2.9	3.0	
Trentham	LM23T	2.9	3.0	
Waikowhai	LMT	4.0	2.9	
Wainuiomata	LMT	2.9	3.0	
Waitangirua	LM23T	2.9	3.0	
Waterloo	LMT	2.8	2.9	

Table 7-18 Health-Criticality Scores for Zone Substation Switchboards

Outcome of the Asset Health Analysis

Frederick Street

The Reyrolle LMT switchboard at Frederick Street had PD mitigation work during 2015 and 2016. 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 are planned for these adjacent circuit breakers in 2019. 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 are revealed to also have high PD levels. PD mitigation works began for these adjacent circuit breakers in 2018 and will be completed in 2019.

Kaiwharawhara

The Reyrolle LMVP switchboard at Kaiwharawhara has previously given unusual readings during PD testing. It seemed to show intermittent PD that moved around the board. Rather than the annual PD snapshot, continuous monitoring was undertaken to locate the cause. The result of the continuous monitoring in 2017 showed that the PD is originating from the Transpower switchyard and not from the board itself. This is being discussed with Transpower to determine whether the PD needs to be remedied.

Johnsonville

PD testing at this substation in 2017 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.

Gracefield

The Gracefield switchboard is Reyrolle Type C which has multiple design issues and, as noted earlier, is being phased out of the network. Replacement of the Gracefield switchboard commenced in 2018 and is planned for completion in 2019.

Partial Discharge Mitigation

A number of other Reyrolle LMT switchboards have circuit breakers with plans for PD mitigation. These are a combination of zone and distribution substations being:

- Zone Substations
    - Mana zone substation
- Distribution Substations
    - 37 Mersey Street
    - 22 Donald Street
    - Wadestown
    - Hutt Hospital
    - Wayside West
    - 24 Hunter Street
    - 26 Balance Street

Further PD mitigation work will be determined by results of ongoing PD testing. This will drive funding allocation for the associated PD mitigation and will be included in future editions of the AMP.

<u>Other Comments</u>

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

Previously, WELL had planned to conduct switchboard refurbishments which would include PD mitigation works as well as installation of arc fault containment measures on LMT switchboards. A review of the switchboard fleet strategy has led to a change in this approach, due to the availability of leakage to frame protection and the ongoing PD mitigation works of zone sub switchboards which has negated the need for these refurbishments.

Recent switchboard replacements such as Karori, Palm Grove, and Evans Bay zone substations already have internal arc containment built into the switchboard design.

Expenditure Summary for Zone Substation Circuit Breakers

Table 7-19 details the expected expenditure on zone substation circuit breakers by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Partial Discharge Mitigation	650	250	250	-	-	-	-	-	-	-
Switchboard Replacement	1,800	-	-	-	-	-	-	-	-	-
Reactive Capital Expenditure	100	100	100	100	100	100	100	100	100	100
Capital Expenditure Total	**2,550**	**350**	**350**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
Preventative Maintenance	137	136	136	136	136	136	136	136	136	136
Corrective Maintenance	21	21	21	21	22	22	22	22	22	22
Operational Expenditure Total	**158**	**157**	**157**	**157**	**158**	**158**	**158**	**158**	**158**	**158**

Table 7-19 Expenditure on Zone Substation Switchboards
($K in constant prices)

Figure 7-10 11 kV Circuit Breakers at The Terrace Zone Substation

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 Figure7-11. The average age of the buildings is 47 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.

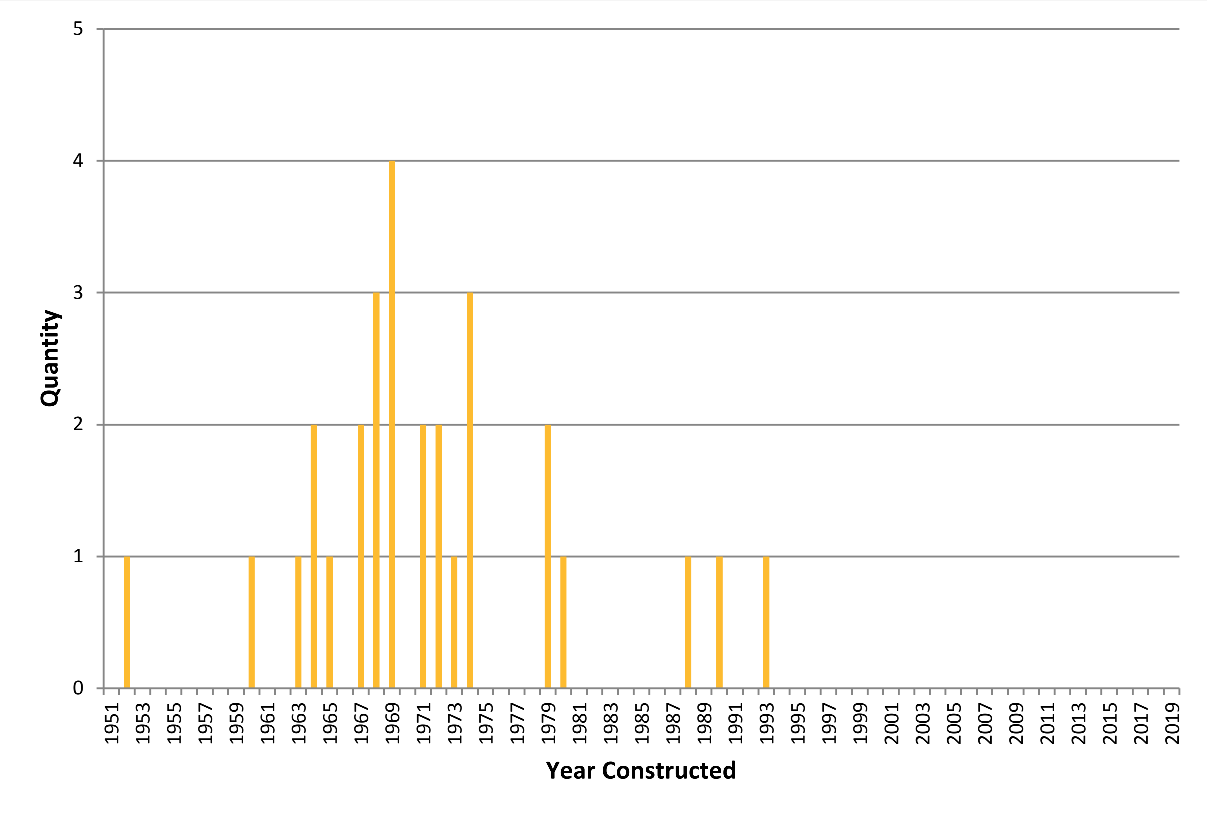


Figure 7-11 Age Profile of Major Substation Buildings

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 7-20 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 7-21 details the expected capex expenditure funded via the DPP allowances on zone substation buildings by regulatory year. These are detailed further in Section 11.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Seismic Strengthening	370	-	-	-	-	-	-	-	-	-
Reactive Capital Expenditure	200	200	200	200	200	200	200	200	200	200
Capital Expenditure Total	**570**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Preventative Maintenance	30	30	30	30	30	30	30	30	30	30
Corrective Maintenance	220	220	220	220	220	220	159	120	120	120
Operational Expenditure Total	**250**	**250**	**250**	**250**	**250**	**250**	**189**	**150**	**150**	**150**

Table 7-21 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 sub transmission distribution lines and low voltage lines, is 39,561. Of this number, 23% are wooden poles and 76.5% are concrete poles. The remaining 0.5% of poles are fibreglass and steel. Another 16,265 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 7-22.

Pole Owner	Wood	Concrete/Other	Total
WELL	9,148	30,413	39,561
Customer	6,518	873	7,391
Chorus	6,463	305	6,768
Wellington City Council	1,309	797	2,106
Total	**23,438**	**32,388**	**55,826**

Table 7-22 Summary of Poles

The average age of concrete/ other poles is 27.5 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 years and nearly 46% 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.

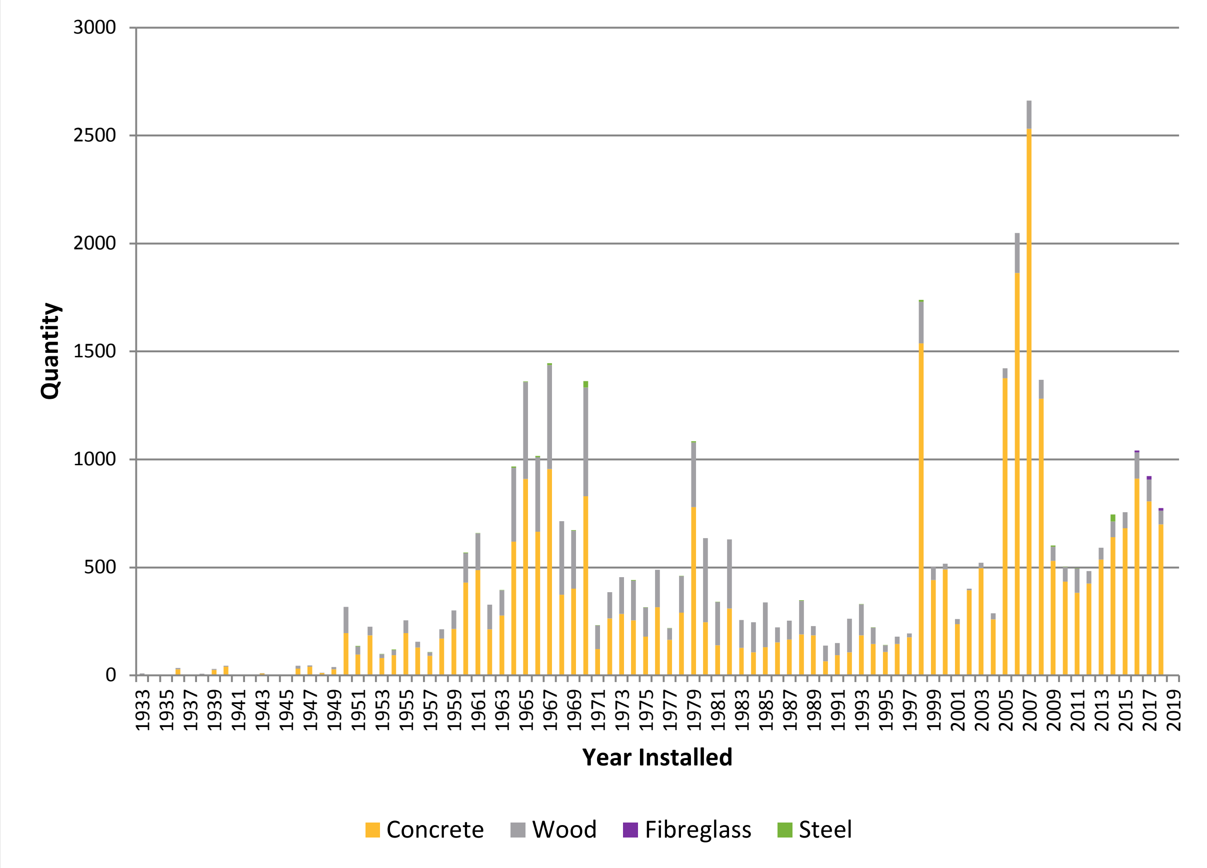


Figure 7-12 Age Profile of Poles

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

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 undertook the inspection of approximately 3,000 poles on private property to confirm ownership and condition. A further review of approximately 3,000 customer-owned service poles was completed in 2018. WELL also occasionally replaces a customer/private pole and then undertakes the ongoing maintenance of such 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 Sub transmission Lines

WELL's 57km of 33 kV sub transmission overhead lines are predominantly AAC conductor on both wood and concrete poles. Overhead line was used for sub transmission in the Hutt Valley and Porirua areas, converting to underground cable at the urban boundary. Sub transmission 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 sub transmission lines is shown in Figure 7-13.

Category	Quantity
33 kV Overhead Line	57km

Table 7-23 Summary of Sub transmission Lines

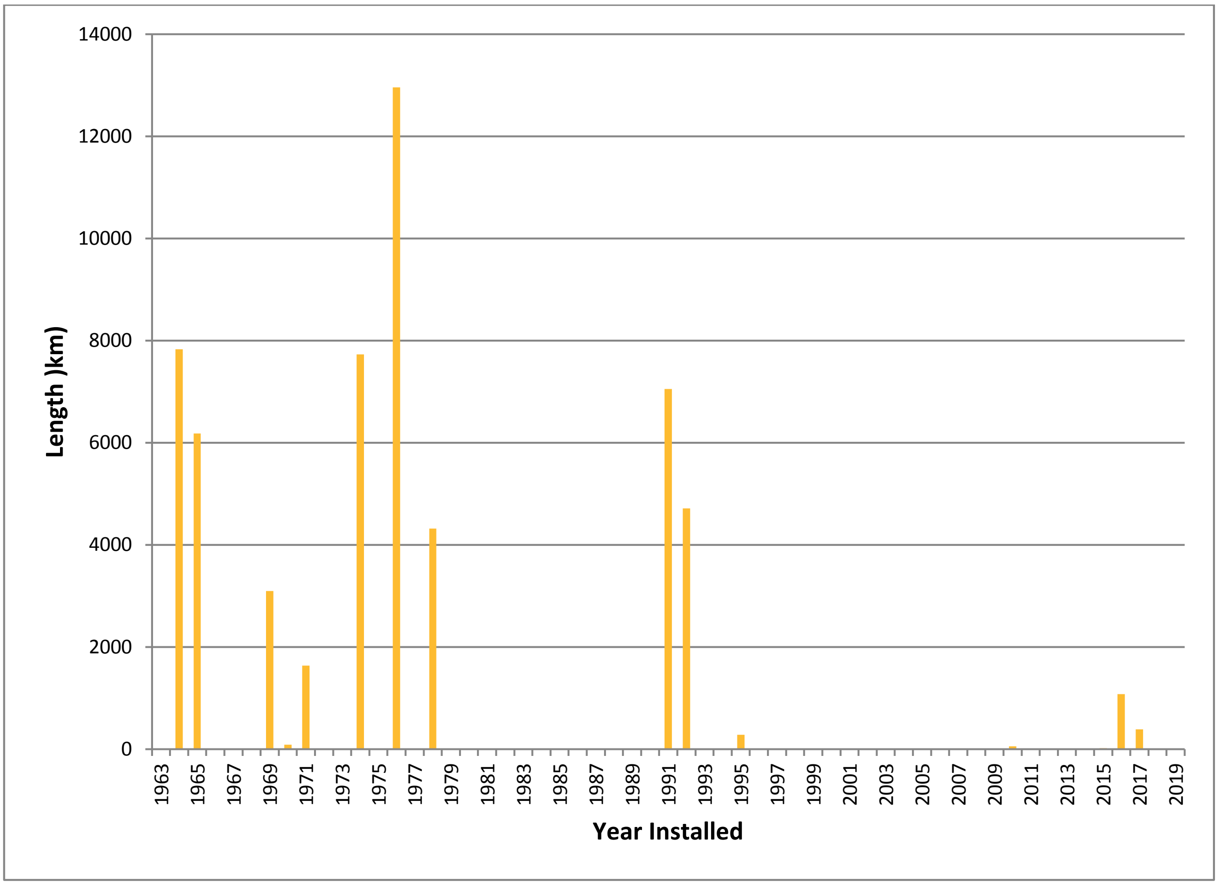


Figure 7-13 Age Profile of Sub transmission Line Conductors

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 due to the high salt presence in the WELL network area. New line reconstruction utilises all aluminium alloy conductor (AAAC). By early 2019, four projects had been completed to put in sections of covered conductor (CCT) to mitigate against vegetation encroachment. 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	593km
Low Voltage Line	1,081km
Streetlight Conductor	810km

Table 7-24 Summary of Distribution Overhead Lines

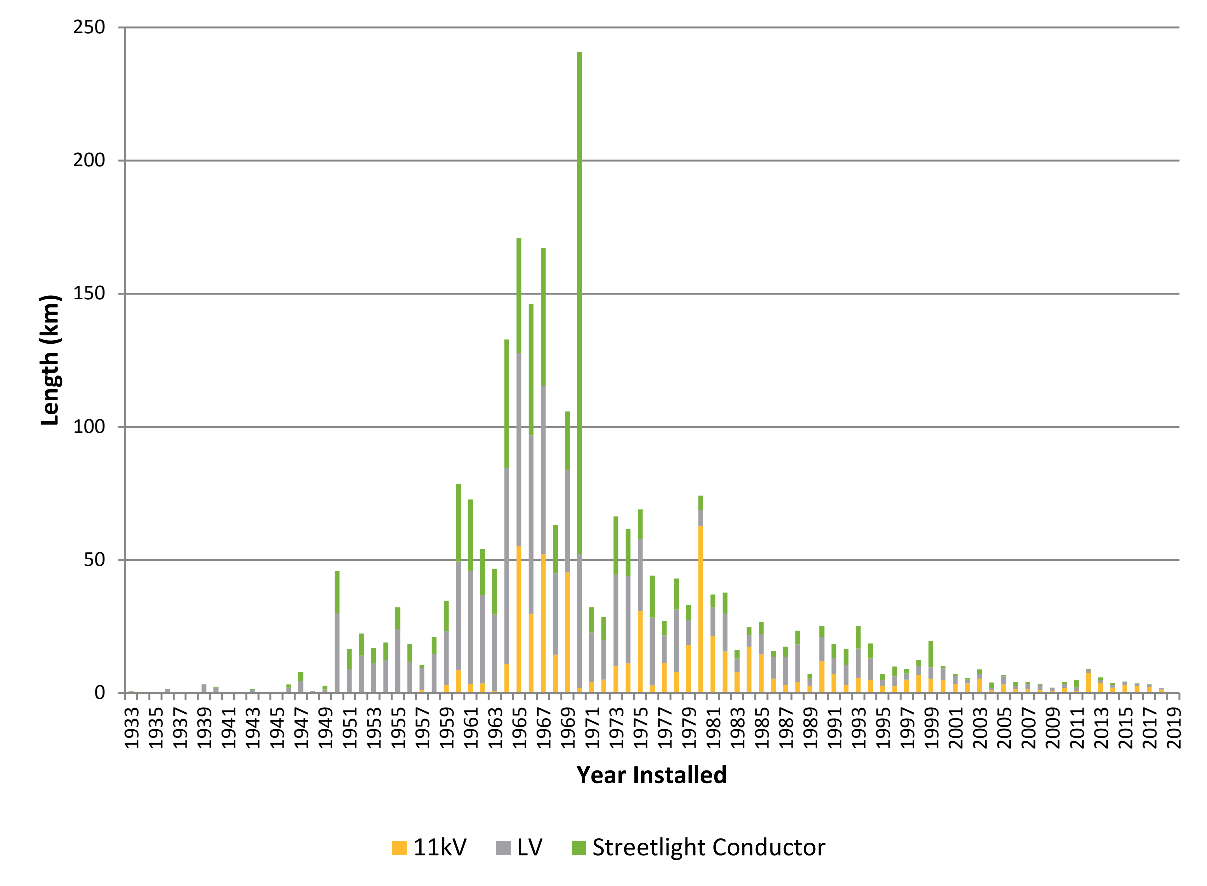


Figure 7-14 Age Profile of Distribution Overhead Line Conductors

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on poles and overhead lines:

Activity	Description	Frequency
Inspection and condition assessment overhead lines by zone/feeder	Visual inspection of all overhead equipment including poles, stay wires, crossarms, insulators, jumpers and connectors, switchgear and transformers. Recording and reporting, and minor repairs as required.	Annually
Concrete, 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 7-25 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. Initial work from destructive testing indicates that expected maximum practical life of conductor (both copper and aluminium) is in the order of 92 years, as shown in Figure 7-15.

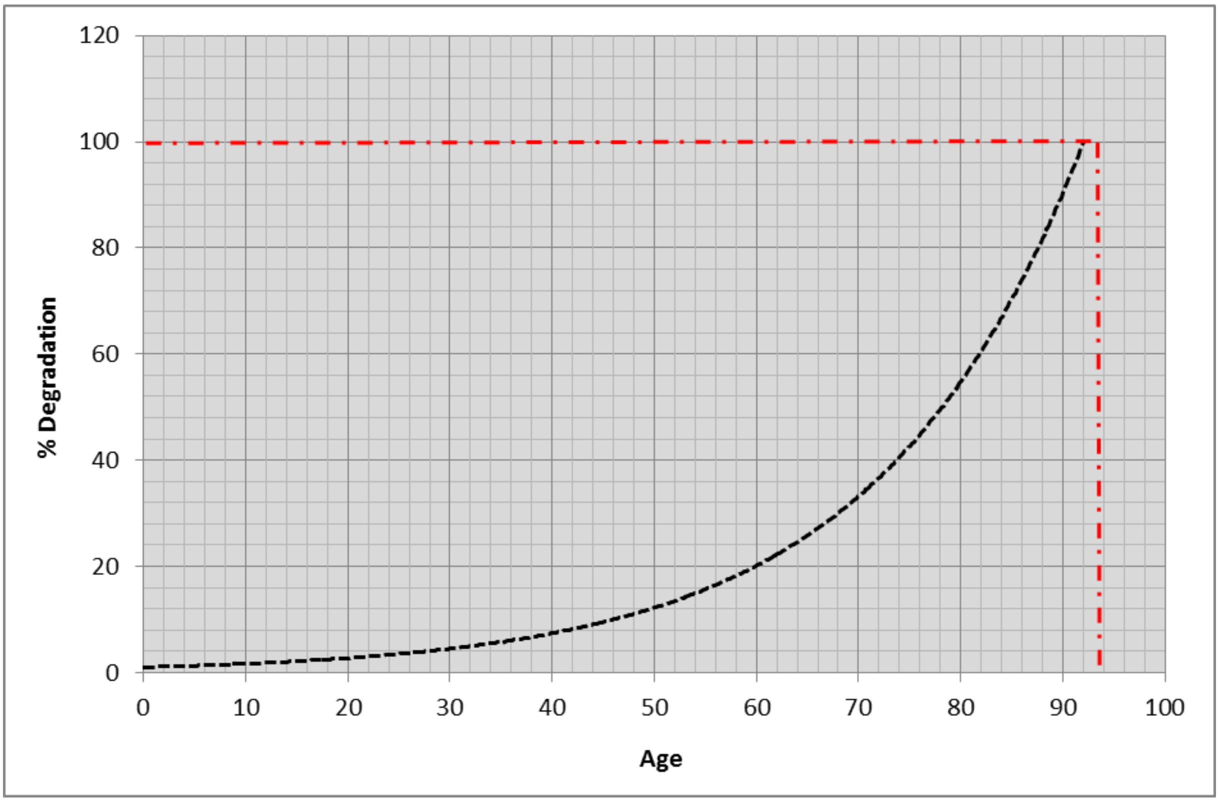


Figure 7-15 Preliminary Data on the Degradation Rates of Overhead Conductor

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 also provides useful remaining life indicators. Approximately 2,000 poles are Deuar tested every year.

The majority of poles on the WELL network are in good condition as the result of a large scale testing and replacement programme, which started between 2004 and 2006. Over three-quarters of the poles installed in the Wellington area are concrete, which are durable and in good condition. The vast 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, which may necessitate pole remediation or replacement. Recently WELL has identified a new type of rot occurring on wooden poles approximately 2m up the pole. This rot is due to insect damage and is being managed via the testing regime which indicates loss of pole structural strength.

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.

Typically the degradation rates for an asset fleet are derived from the historical evidence showing the rate at which assets trend from 100% health when new to 0% at end of life. The health curves for poles, utilised for forecasting future replacement quantities, have been based on the information available from testing already completed (including estimated remaining lives) and rates of tagged poles by age group. The results of this analysis are shown in Figure 7-16 showing the probability of a wood pole not being tagged by age group.

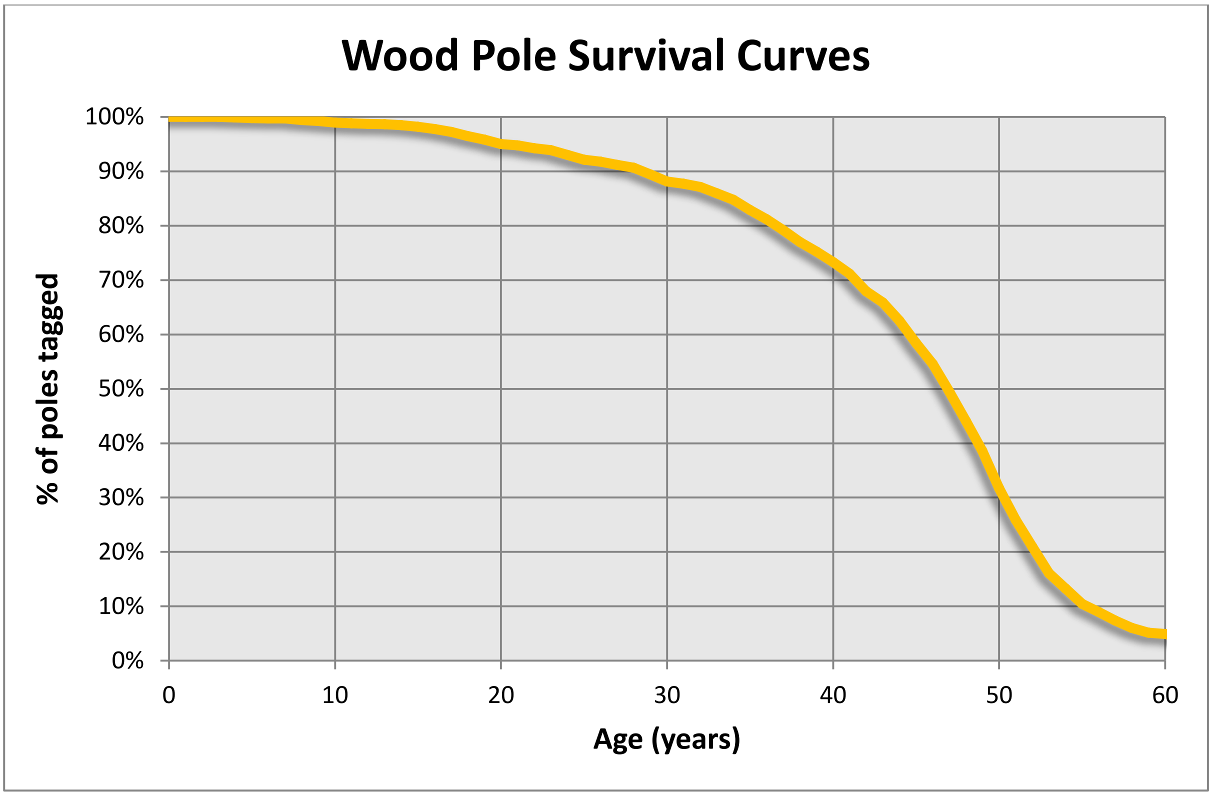


Figure 7-16 Probability of a Wood Pole Not Being Tagged by Age

Figure 7-17 shows the health-criticality matrix of WELL's fleet of poles. Pole asset health is determined solely by the unit's condition ranking, while asset criticality is determined by the voltage of the lines connected to the pole and the number of 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	6	10	7	-	-	-
	1.5	-	-	-	-	-	-	-
	2.0	538	151	130	62	1	1	-
Asset Health	2.5	-	-	-	-	-	-	-
	3.0	10,306	2,289	2,589	736	22	48	-
	4.0	5,592	780	1,156	426	2	16	-
Best Health	5.0	4,931	1,003	1,174	450	-	4	-

Figure 7-17 Pole Health-Criticality Matrix

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 or when cross arms require replacement. All new insulators are of the solid core post type as these do not suffer the same modes of failure as pin insulators, and provide a higher level of reliability in polluted environments and lightning prone areas.

High wind loadings can sometimes result in fatigue failures around line hardware such as binders, compression sleeves, line guards and armour rods on the older AAC lines that have historically been used on the Wellington network. 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. 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.

		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							
	2.0		25	7				
	2.5							
	3.0		102	42		7		1
	4.0		53	2		1		
Best Health	5.0							

Figure 7-18 Dx Line Health-Criticality Matrix[33]

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

[33] Each number in this matrix refers to an individual 11kV feeder

engineering investigation within three months. For all pole tag colours the climbing of tagged poles by contractors is prohibited.

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

All replacement poles are concrete except where the location requires the use of timber 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.

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, cross arms and poor condition poles replaced. These feeders have had a significant improvement in performance since this work was completed.

A general programme of conductor replacement, targeting conductors based on age, type and location, will be required in specific areas but at this stage, testing has shown that an extensive conductor replacement programme is not required. Further testing is underway to evaluate all the conductor types and conditions on the network which will inform future AMP's.

Expenditure Summary for Overhead Lines

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Reliability Improvement Projects	1,571	2,107	1,592	1,717	1,413	1,413	1,455	1,499	1,544	1,590
Pole Replacement Programme	7,300	7,400	7,500	7,500	7,500	7,000	7,000	7,000	7,000	7,000
Conductor Replacement Programme	250	255	260	265	271	675	1,011	1,041	1,073	1,105
Area Rebuild Projects	-	-	-	500	900	900	1,800	1,800	1,800	1,800
Reactive Capital Expenditure	500	500	500	500	500	1,000	1,000	1,000	1,000	1,000
Capital Expenditure Total	**9,621**	**10,262**	**9,852**	**10,482**	**10,584**	**10,988**	**12,266**	**12,340**	**12,417**	**12,495**
Preventative Maintenance	439	437	434	433	431	429	428	427	428	428
Corrective Maintenance	824	763	764	858	866	874	880	880	880	880
Operational Expenditure Total	**1,263**	**1,200**	**1,198**	**1,291**	**1,297**	**1,303**	**1,308**	**1,307**	**1,308**	**1,308**

Table 7-26 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, normally open radial feeders interconnecting neighbouring rings or zone substations. This part of the network uses automatically operating circuit breakers, with differential protection on cables between distribution substations, rather than manually operated ring main switches between switching zones. This results in higher reliability as smaller sections of network are affected by cable faults. However due to the nature of the CBD, any repairs required to the distribution system take considerably longer than standard replacement times. CBD repairs also incur considerable costs for traffic management and road surface or pavement reinstatement.

Outside the Wellington CBD, the 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)	1,180km
Low Voltage cable (incl. risers)	1,695km
Streetlight cable	1,105km

Table 7-27 Summary of Distribution Cables

Approximately 88% of the underground 11 kV cables are PILC and PIAS and the remaining 12% 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 7-19.

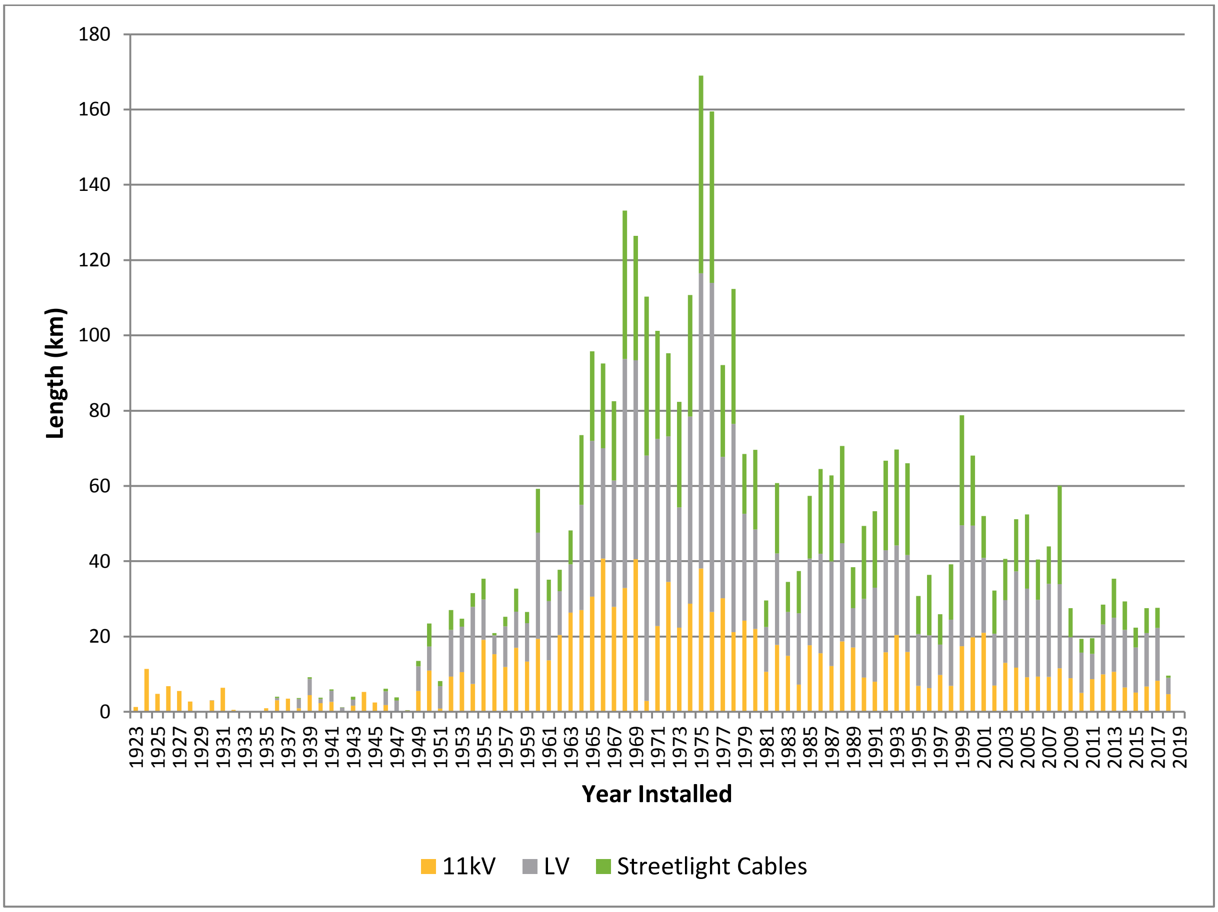


Figure 7-19 Age Profile of Distribution Cables

Maintenance Activities

Maintenance of the underground distribution cable network is limited to visual inspection and thermal imaging of cable terminations. Cables are operated to failure and then either repaired or 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.

Research in 2017 has resulted in an investigation into the potential of a partial discharge condition monitoring programme. Allowance has been made in this AMP to begin a preventative maintenance programme using partial discharge testing. These test results will be used to develop a condition profile of the cable fleet with approximately 400 cable segments scheduled to be done annually.

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 (which are less controllable).

In 2017 there was a noticeable increase in the number of cable related failures (17 failures in the calendar year) and this has continued in 2018 (20 failures in the calendar year). Most of these failures have occurred on LV cables and have not impacted reliability statistics.

		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	5	4	1				
	2.5							
	3.0	11	13	11			2	1
	4.0	55	59	28		4		1
Best Health	5.0	8	8	3				

Figure 7-20 11 kV Cable Health-Criticality Matrix[34]

Renewal and Refurbishment

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

Cable termination replacement is driven by visual inspection when signs of discharge or significant compound leaks are found, results of thermography scans indicating hot connections, as well as analysis of fault rates. The exception to this is 11 kV cast metal pothead terminations where analysis of fault rates, together with a risk assessment, has resulted in a decision to replace them with heat shrink terminations.

[34] Each number in this matrix refers to an individual 11kV feeder

Expenditure Summary for Distribution and LV Cable

Table 7-28 details the expected expenditure on distribution and LV cable by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Asset Replacement and Renewal Capex	100	750	500	1,700	750	1,500	1,500	3,000	3,000	5,000
Reactive Capital Expenditure	200	200	250	250	250	250	250	250	250	250
Capital Expenditure Total	**300**	**950**	**750**	**1,950**	**1,000**	**1,750**	**1,750**	**3,250**	**3,250**	**5,250**
Preventative Maintenance (PD Testing)	200	200	200	200	200	200	200	200	199	200
ARR Opex	200	200	200	200	200	200	200	200	200	200
Corrective Maintenance	575	575	575	575	575	575	575	575	573	563
Operational Expenditure Total	**975**	**975**	**975**	**975**	**975**	**975**	**975**	**975**	**972**	**963**

Table 7-28 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 the remaining 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 where exposed to sea salt spray, a transformer may not reach this age due to corrosion. The age profile of distribution transformers is shown in Figure 7-21.

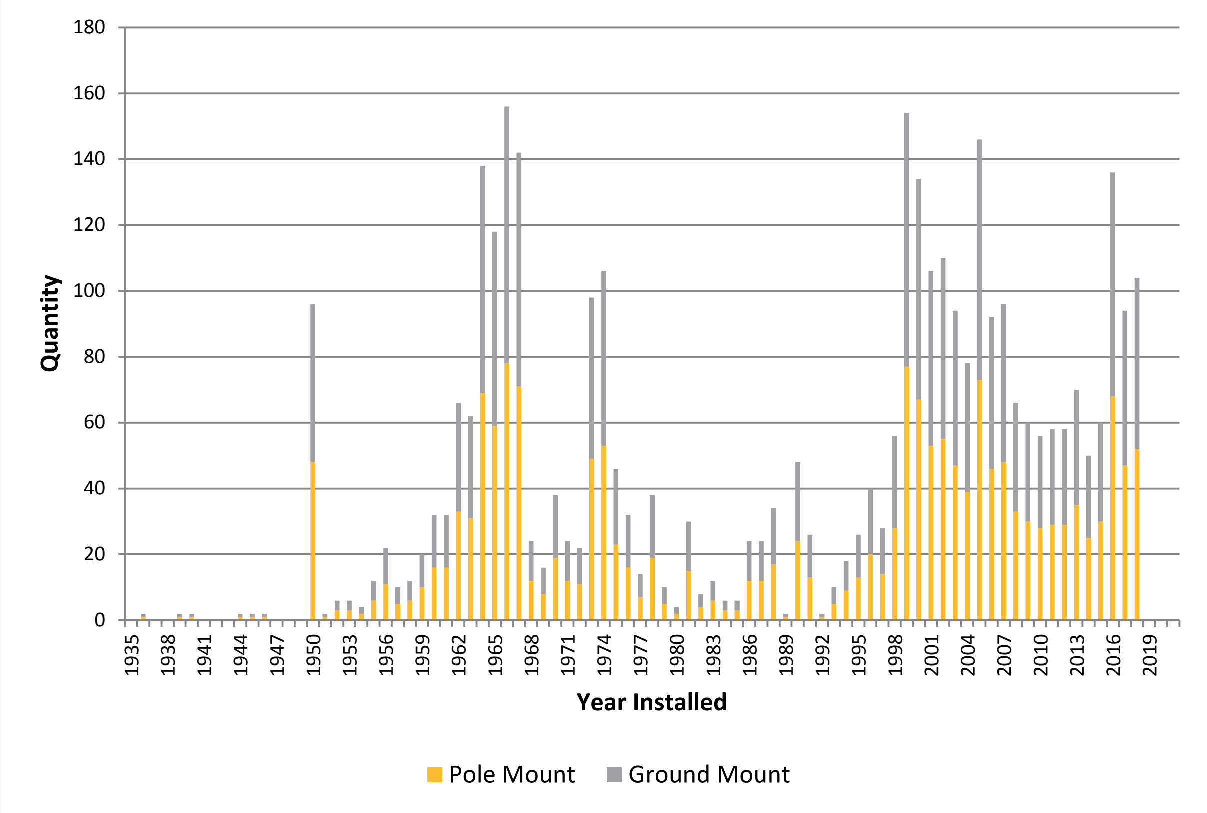


Figure 7-21 Age Profile of Distribution Transformers

In addition to pole and integral pad mount berm substations, WELL owns 512 indoor substation kiosks and occupies a further 668 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 7-29.

Category	Quantity
Distribution transformers	4,399
WELL owned substations	3,702
Customer owned substations	668
Distribution substations – Total	**4,370**

Table 7-29 Summary of Distribution Transformers and Substations

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on distribution substations and associated equipment:

Activity	Description	Frequency
Inspection of Distribution Substations	Routine inspection of distribution substations to ensure asset integrity, security and safety. Record and report defects, undertake minor repairs as required. Record MDIs where fitted.	Annually
Grounds maintenance	General programme of ground and building maintenance for distribution substations.	Ongoing
Fire Alarm Test	Inspect and test passive fire alarm systems.	3 monthly
Visual Inspection and Thermal Image (Ground Mount Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annual
Visual Inspection and Thermal Image (Pole Transformer)	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections.	Annual
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance.	5 yearly

Table 7-30 Inspection and Routine Maintenance Schedule for Distribution Transformers

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							
	2.0	2	7	15	5	2	2	
	3.0	275	598	1,243	325	301	222	
	4.0	232	294	463	154	64	32	
Best Health	5.0							

Figure 7-22 Distribution Transformer Health-Criticality Matrix

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

Internal Bushing Transformers

Ground-mounted transformers manufactured by Bonar Long, Bryce and ASEA were installed between 1946 and 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.

Pole-mounted Transformers

Analysis of transformer faults indicate that transformers between 25 and 40 years old have been failing at a greater rate than those between 40 and 60 years. It is suspected that these premature failures may be potentially due to modern transformers having more optimised designs than older units. Given the low cost of pole-mounted transformers and the small area impacted by a single failure, no further action is planned at this stage to address the issue.

Renewal and Refurbishment

If a distribution transformer is found to be in an unsatisfactory condition during its regular inspection, it is programmed for corrective maintenance or replacement. In-service transformer failure is rare and is investigated to determine the cause. This assessment determines if the unit is repaired, refurbished, or 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.

Expenditure Summary for Distribution Substations

Table 7-31 details the expected expenditure on distribution substations by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Seismic Strengthening	2,400	470	500	500	650	-	-	-	-	-
Earthing Upgrades	300	150	300	300	300	300	300	300	300	300
Lock Replacement	200	100	200	200	200	200	200	200	200	200
Asset Replacement and Renewal Capex	1,100	1,100	1,213	1,311	2,500	2,500	2,500	2,500	2,500	2,500
Reactive Capital Expenditure	500	500	500	500	500	500	500	500	500	500
Capital Expenditure Total	**4,500**	**2,320**	**2,713**	**2,811**	**4,150**	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**
ARR Opex	195	173	152	128	105	86	75	211	118	118
Preventative Maintenance	635	635	635	635	635	635	635	635	635	535
Corrective Maintenance	1,727	1,694	1,835	1,863	1,907	1,955	1,960	1,829	1,920	1,922
Operational Expenditure Total	**2,557**	**2,502**	**2,622**	**2,626**	**2,647**	**2,676**	**2,670**	**2,675**	**2,673**	**2,575**

Table 7-31 Expenditure on Distribution Substations ($K in constant prices)

Figure 7-23 Anti-graffiti Mural on Kiosk Distribution Substation

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 1,279 distribution circuit breakers and 2,567 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 Figure7-25 and Figure 7-26.

Figure 7-24 11kV Switchgear Replacement at 541 Hebden Crescent Substation

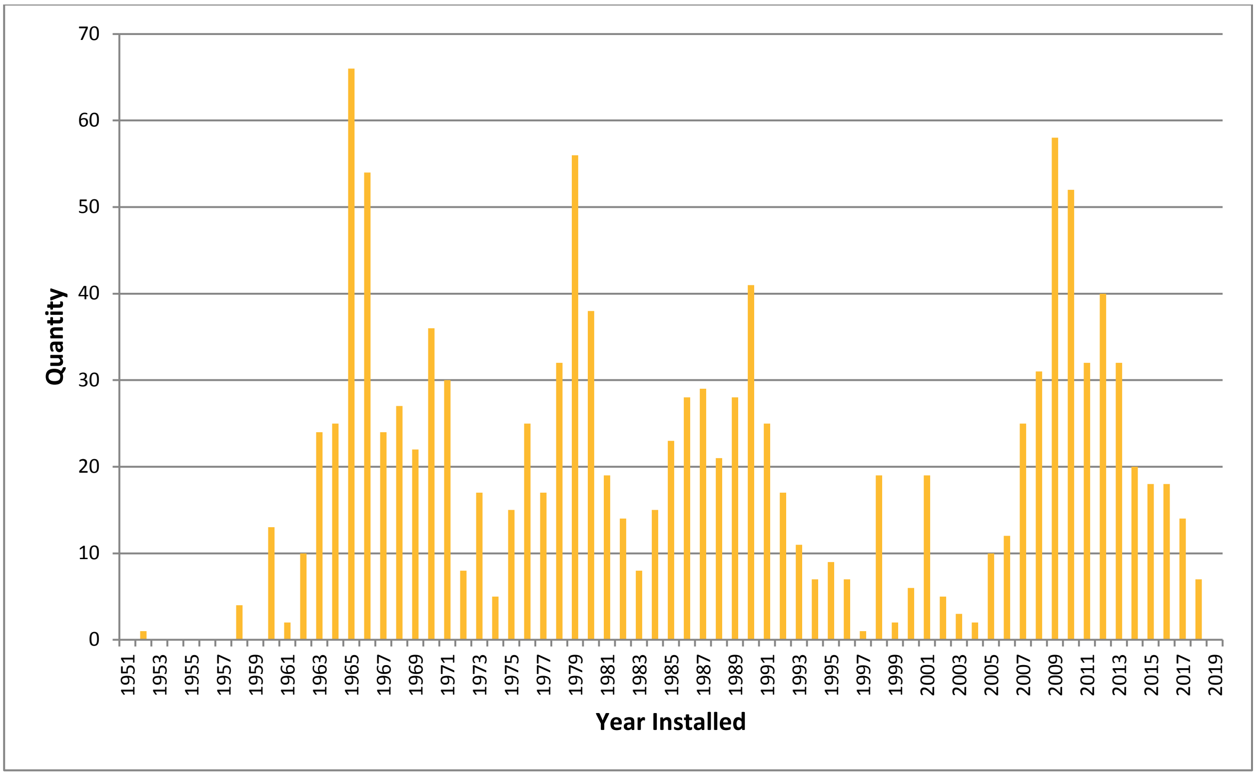


Figure 7-25 Age Profile for Distribution Circuit Breakers

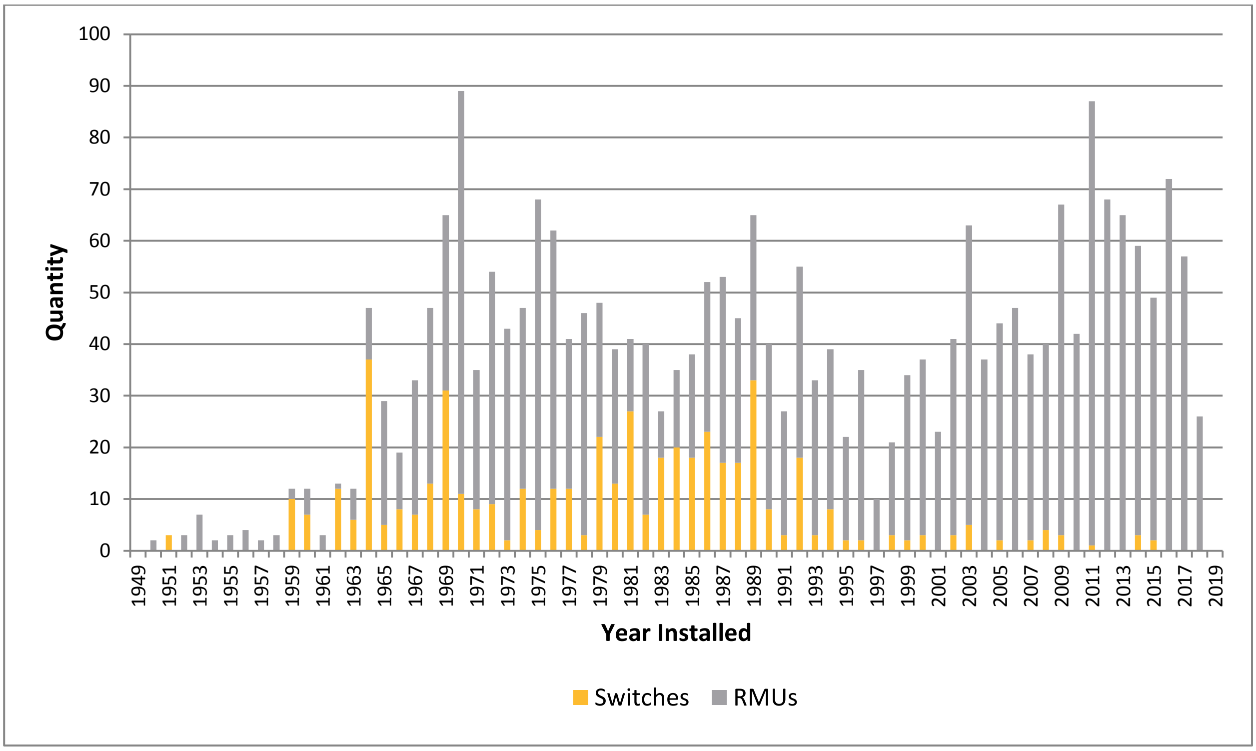


Figure 7-26 Age Profile of Other Ground Mounted Distribution Switchgear

The average age of distribution circuit breakers in the network is around 32 years, while the average age of ring main units is 29 years. A summary of circuit breakers and ground mounted distribution switchgear, of both stand-alone and ring main unit types, is shown in Table 7-32 and Table 7-33.

Category[35]	Quantity
Distribution Circuit Breakers	1,279
Oil Insulated Switches	413
Oil Insulated RMUs	217
SF_6 Insulated Switches	91
SF_6 Insulated RMUs	798
Solid Insulated RMUs	1,048

Table 7-32 Summary of Ground Mounted Distribution Switchgear

Manufacturer	Breaker Type	Quantity
ABB	SF_6	27
AEI	Oil	56
BTH	Oil	53
Crompton Parkinson	Oil	1
GEC/Alstom	Oil	58
Hawker Siddeley	Vacuum	21
Merlin Gerin / Schneider	SF_6	309
	Vacuum	2
Reyrolle	Oil	632
	Vacuum	59
South Wales	SF_6	36
Statter	Oil	25[36]
Total		**1,279**

Table 7-33 Summary of Distribution Circuit Breakers by Manufacturer

Maintenance Activities

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

[35] There is a switchgear reclassification which contributed to the changes in quantities.

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

Activity	Description	Frequency
Visual Inspection of Switchgear	Visual inspection of equipment, and condition assessment based upon visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
Switchgear Maintenance (Magnefix)	Clean and maintain Magnefix unit, inspect and replace link caps as required, test fuses, check terminations where possible.	5 yearly
Circuit Breaker Maintenance (Oil CB)	Withdraw and drain OCB, ensure correct mechanical operation, dress or replace contacts as required, undertake minor repairs, refill with clean oil, return to service. Trip timing test before and after service	5 yearly
Switch Maintenance (Oil Switch)	Clean and maintain oil switch unit, drain oil and check internally, check terminations and cable compartments. Ensure correct operation of unit. Refill with clean oil.	5 yearly
Circuit Breaker Maintenance (Vacuum or Gas CB)	Withdraw CB and maintain carriage and mechanisms as required, record condition of interrupter bottles where possible, clean and return to service. Trip timing test before and after service	5 yearly
Switch Maintenance (Vacuum or Gas Switch)	Clean and maintain switch unit, check terminations and cable compartments. Ensure correct operation of unit. Check gas / vacuum levels.	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 7-34 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 7-27 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	15	18	63	12	-	-	-
	1.5	31	29	154	22	1	5	-
Asset Health	2.0	-	5	9	1	-	3	-
	2.5	46	33	117	44	120	67	-
	3.0	115	248	805	205	476	293	-
	4.0	28	50	154	34	62	50	-
Best Health	5.0	19	13	59	19	9	13	-

Figure 7-27 Distribution Switchgear Health-Criticality Matrix

Specific condition issues for distribution switchgear are:

Solid Insulation Magnefix

Magnefix switchgear is cleaned five-yearly, with targeted cleaning for a number of sites undertaken more frequently as a corrective maintenance activity. Magnefix switchgear is generally reliable however there are specific cleaning requirements to avoid tracking problems associated with the resin body casing due to the accumulation of dust and other deposits (such as blown salt and diesel fumes).

There have been past experiences of Magnefix failures on the network due to a termination failure. The “Figure 8” connectors on some older units (typically installed between 1968 and 1975) fail under heavy loads due to heating and thermo-mechanical cycling problems. The failures all occurred on residential feeders with recent load growth and during the winter evening peak. A survey of older units has shown a number with low or leaking termination grease levels, which may be a physical sign of heating in the connector. These units are prioritised for topping up of grease levels within the termination cable boxes.

There are also a further 13 sites with KES 10 Krone switches which are 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 2018, there are 19 Long and Crawford ring main units 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, and a programme to replace Long and Crawford commenced in 2016, for completion by 2022. 13 of the 19 sites are expected to be completed before the end of 2019.

Statter

As at October 2018, there are 55 sites with Statter switchgear, with 138 units in service including circuit breakers, oil switches and fuse switches, installed between 1955 and 1991. There are 7 sites which have replacement projects that are expected to be completed before end 2019.

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 scheduled for completion in 2022.

Renewal and Refurbishment

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.

Low Voltage Distribution Switchgear (Substation)

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

In early 2016 a safety alert was issued to contractors prohibiting live work between the transformer bushings and the low voltage busbars, and work in situations where items may contact live busbars. This has been followed up with further work to detail an arc flash PPE 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 7-35 details the expected expenditure on ground-mounted switchgear by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Long and Crawford Replacement Programme	630	630	473	-	-	-	-	-	-	-
Statter Replacement Programme	1,000	1,125	1,000	-	-	-	-	-	-	-
Other Asset Replacement and Renewal Capex	310	245	245	985	2,500	3,000	3,000	3,000	3,000	3,000
Reactive Capital Expenditure	450	450	650	650	650	650	650	650	650	650
Capital Expenditure Total	**2,390**	**2,450**	**2,368**	**1,635**	**3,150**	**3,650**	**3,650**	**3,650**	**3,650**	**3,650**
ARR Opex	100	100	100	100	100	100	100	100	100	100
Preventative Maintenance	600	600	600	600	600	600	600	600	600	600
Corrective Maintenance	554	554	554	554	554	554	554	617	554	554
Operational Expenditure Total	**1,254**	**1,254**	**1,254**	**1,254**	**1,254**	**1,254**	**1,254**	**1,317**	**1,254**	**1,254**

Table 7-35 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 1,134[37] 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 7-36.

Type	Quantity[38]
Customer service pillar	8,998
Customer service pit	2,118
Link pillars, pits and cabinets	1,134
Total	**12,250**

Table 7-36 Summary of LV Units

[37] Reclassification of link pillars, pits, cabinets and LV boards has been undertaken.

[38] There are approximately 6,119 low voltage pillars, pits, cabinets and LV boards that have unknown installation dates and these have not been included.

An age profile of LV Units (pillars, pits, cabinets and boards) is shown in Figure 7-28.

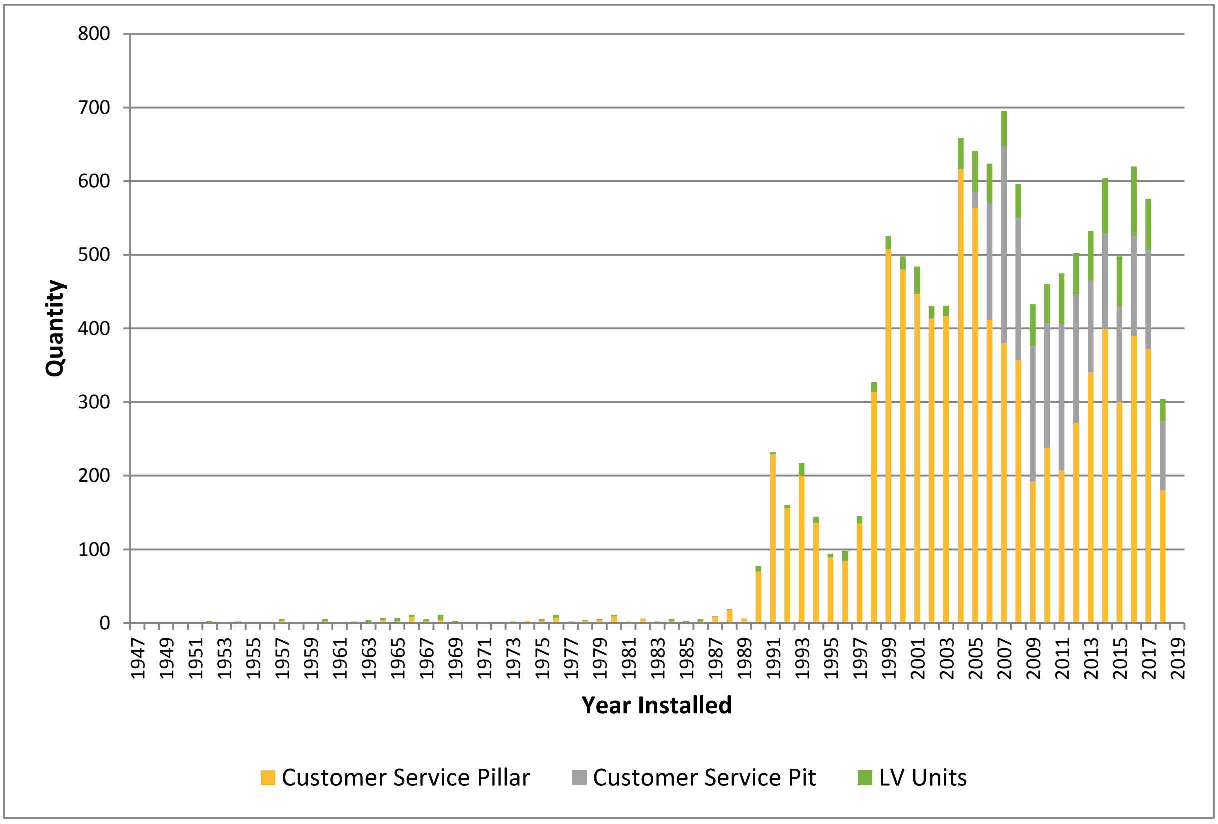


Figure 7-28 Age Profile of Pillars, Pillars and Cabinets

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on low voltage pits and pillars, for either consumer service connection and fusing or network LV linking:

Activity	Description	Frequency
Inspection of Service Pillars	Visual inspection and condition assessment of service pillar, minor repairs to lid as required.	5 yearly
Inspection of Service Pits	Visual inspection and condition assessment of service pit, minor repairs as required.	5 yearly
Inspection of Link Pillars	Visual inspection and condition assessment of link pillar, thermal imaging and minor repairs as required.	5 yearly
U/G link box inspection including Thermal Image	Visual inspection and condition assessment of link box, thermal imaging and minor repairs as required.	5 yearly

Table 7-37 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 7-38 details the expected expenditure on low voltage pits and pillars by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Asset Replacement and Renewal Capex	150	150	150	150	150	150	150	150	150	150
Reactive Capital Expenditure	150	150	150	150	150	150	150	150	150	150
Capital Expenditure Total	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**300**
Preventative Maintenance	60	60	60	60	60	60	60	60	60	60
Corrective Maintenance	50	50	50	50	50	50	50	50	50	50
Operational Expenditure Total	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**

Table 7-38 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 three being older hydraulic types. The individual types of auto-reclosers are shown in the Table 7-39.

Manufacturer	Insulation	Model	Quantity
G&W	Solid/Vacuum	ViperS	13
Reyrolle	Oil	OYT	1
McGraw-Edison	Oil	KFE	2
Total			**16**

Table 7-39 Summary of Recloser Types

The age profile of WELL's reclosers is shown in Figure 7-29.

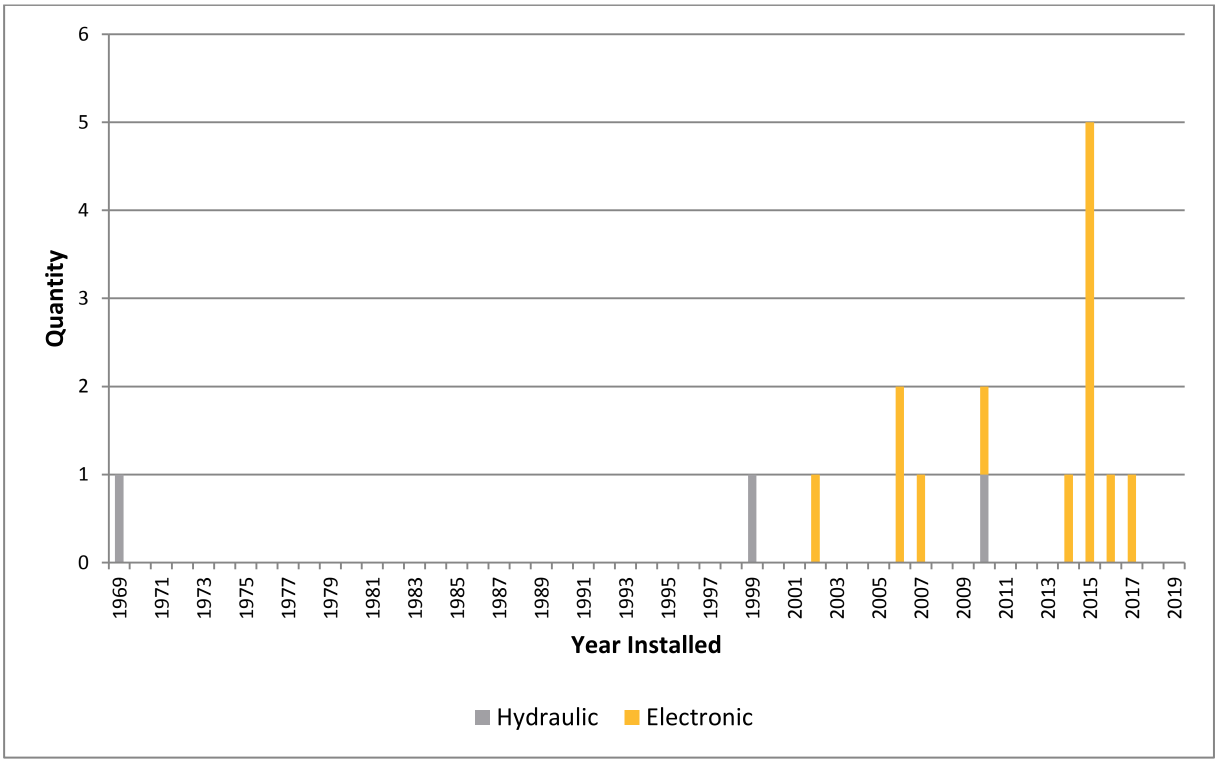


Figure 7-29 Age Profile of Reclosers

Maintenance Activities

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

Activity	Description	Frequency
Visual Inspection and Thermal Image	Visual inspection of equipment and condition assessment based upon visible defects. Thermal image of accessible connections.	Annually
Recloser Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication.	Annually
Recloser Service	Maintenance of recloser, inspect and maintain contacts, change oil as required, prove correct operation.	3 yearly
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance.	5 yearly

Table 7-40 Inspection and Routine Maintenance Schedule for Auto Reclosers

Renewal and Refurbishment

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

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

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 has been published in 2018 which will assist in defining these numbers going forward.

Expenditure Summary for Reclosers

Table 7-41 details the expected expenditure on reclosers by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Asset Replacement and Renewal Capex	588	441	882	-	-	-	-	-	-	-
Capital Expenditure Total	**588**	**441**	**882**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Preventative Maintenance	8	7	7	7	7	7	7	7	7	7
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**18**	**17**	**17**	**17**	**17**	**17**	**17**	**17**	**17**	**17**

Table 7-41 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 7-42.

Category	Quantity
Gas Switches	74
Air Break Switches	277
Knife Links	83
Dropout Fuses	2,130
Dropout Sectionalisers	12
Total	**2,576**

Table 7-42 Summary of Pole Mounted Distribution Switchgear

The age profiles of these devices are shown in Figure 7-30.

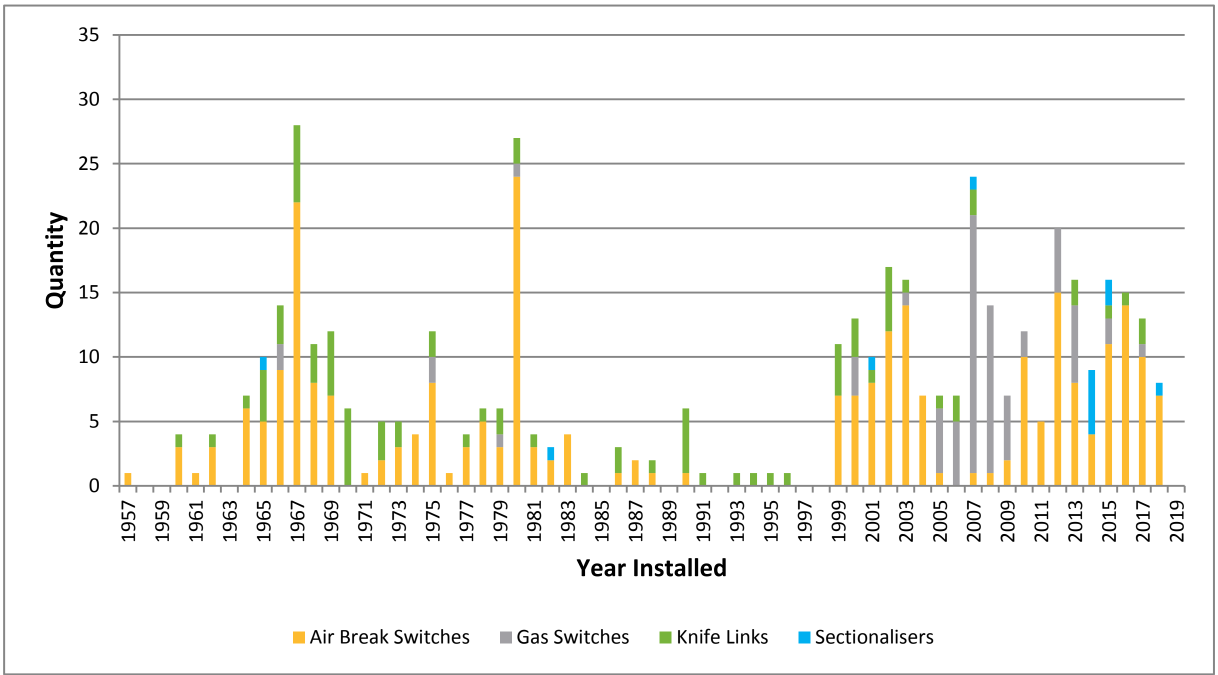


Figure 7-30 Age Profile of Overhead Switchgear and Devices

Maintenance Activities

The following routine planned inspection, testing and maintenance activities that are undertaken on overhead switches, links and fuses are shown in Table 7-43.

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 7-43 Inspection and Routine Maintenance Schedule for Overhead Switch Equipment

All overhead switches and links are treated in the same manner, and are maintained under the preventative maintenance programme detailed above. Overhead HV fuses are visually inspected during both the annual overhead line survey and at the time of transformer maintenance (for fuses supplying overhead transformers). The large quantity and low risk associated with fuses does not justify an independent inspection and maintenance programme.

Condition of Overhead Switches, Links and Fuses

Generally, the condition of overhead equipment on the network is good. The environment subjects equipment to wind, salt spray, pollution and debris, which causes a small number of units to fail annually. Common modes of deterioration are corrosion of steel frame components and operating handles, mechanical damage to insulators, as well as corrosion and electrical welding of contacts. In harsh environments, fully enclosed gas insulated switches with stainless steel components are now being used.

A problem has previously been identified with some types of expulsion drop out (EDO) fuses that were overheating. This is a result of the use of different metals causing the pivot point on the fuse holder to seize and prevent the fuse holder from operating as designed. Over the past four years this has not been a major issue and therefore replacement currently only occurs as required. The same can be said for in-line links, which have 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 a better quality assurance process with regards to installation was 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.

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 cross arm replacements undertaken over recent years, a large number of overhead switches have now been replaced. Replacement generally occurs following a poor condition assessment result from the routine inspections, or at the time of pole or cross arm replacement if the condition of the switch justifies this at that time.

Expenditure Summary for Overhead Switchgear

Table 7-44 details the expected expenditure on overhead switchgear by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Reactive Capital Expenditure	200	200	200	200	200	200	200	200	200	200
Capital Expenditure Total	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**	**200**
Preventative Maintenance	120	120	120	120	120	120	120	120	120	120
Corrective Maintenance	124	125	126	127	129	130	131	132	132	132
Operational Expenditure Total	**244**	**245**	**246**	**247**	**249**	**250**	**251**	**252**	**252**	**252**

Table 7-44 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 different DC voltages: 24, 30, 36, 48, and 110V, largely for historical reasons, however, it has standardised on 24V for all new or replacement installations.

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on substation DC supply systems (battery banks):

Activity	Description	Frequency
Inspection and monitoring of battery & charger condition.	Routine visual inspection of batteries, chargers and associated equipment. Voltage check on batteries and charger.	Annually
Comprehensive battery discharge test.	Comprehensive battery discharge test for all batteries, measurement and reporting of results.	2 yearly (Zone only)

Table 7-45 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 546[39] battery banks across 305 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 a number of 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 7-46 details the expected expenditure on substation batteries by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Asset Replacement and Renewal Capex	266	266	300	300	300	300	300	300	299	300
Capital Expenditure Total	**266**	**266**	**300**	**300**	**300**	**300**	**300**	**300**	**299**	**300**
Preventative Maintenance	20	20	20	20	20	20	20	20	20	20
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**	**40**

Table 7-46 Expenditure on Substation Batteries (\$K in constant prices)

7.5.8.2 Secondary Protection Devices

Fleet Overview

Secondary 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 and microprocessor technology.

[39] This excludes common alarms requiring 9V batteries.

Protection devices are generally mounted as part of a substation switchboard but can also be housed in dedicated panels.

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.

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 required security and the risk to supply.

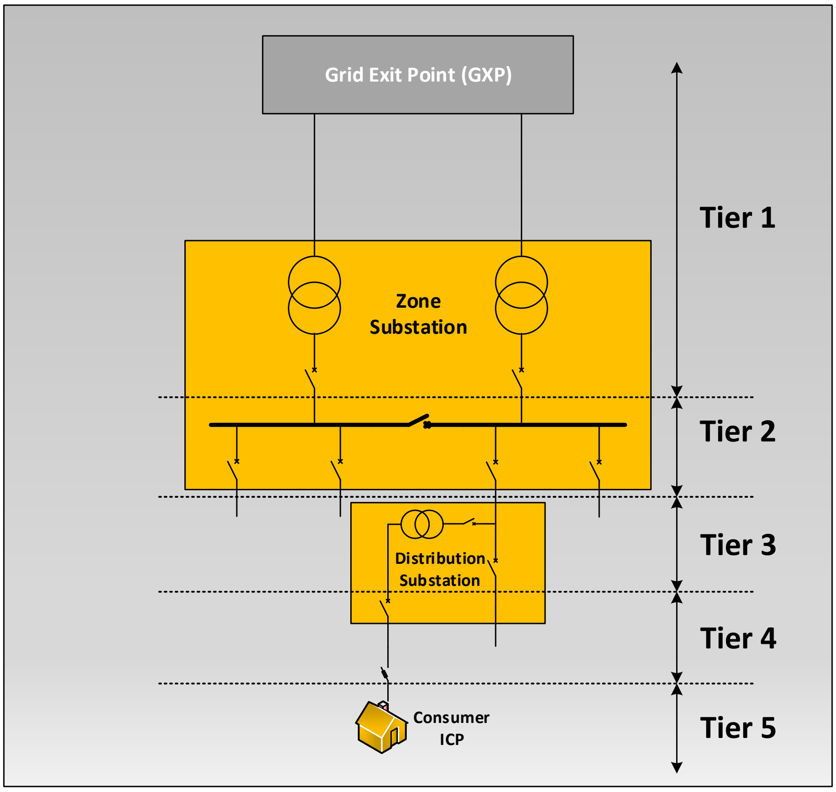


Figure 7-31 WELL Protection Tier System

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. This is 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.

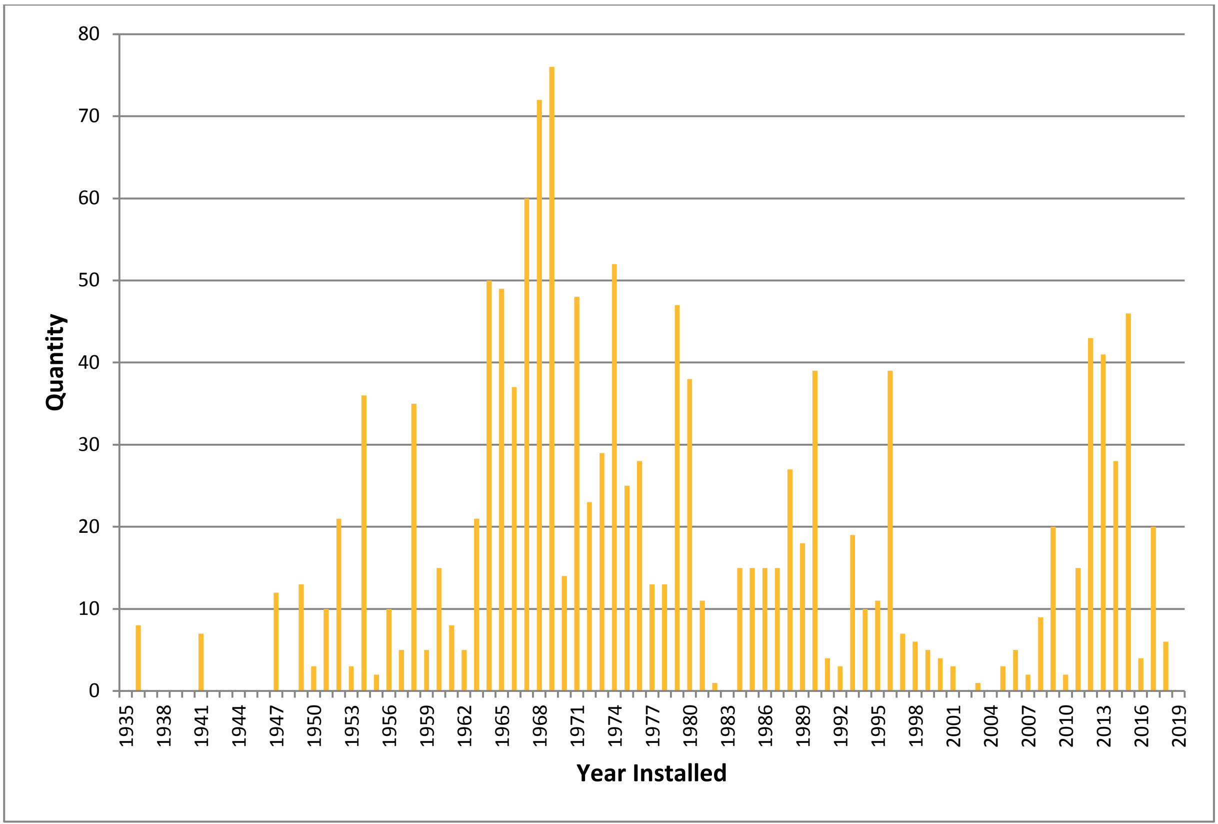


Figure 7-32 Age Profile of Protection Relays

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 7-47 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 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.

The following programmes and projects are included in the asset replacement[40] and maintenance budgets:

- Ongoing replacement of devices with identified risk;
- Replacement of the entire Gracefield Zone Substation protection systems (Tier 1 and Tier 2) in coordination with the primary switchboard replacement; and
- Tier 1 replacement program targeting highest priority sites following on from RTU upgrades or GXP upgrades.

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 7-48 details the expected expenditure on protection relays by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Tier 1 Replacement Programme	42	1,140	760	760	760	760	760	380	-	-
Tier 2 Replacement Programme	50	-	405	300	400	300	400	400	480	380
AVR Replacement	25	55	60	60	60	60	60	-	-	-
Capital Expenditure Total	**117**	**1,195**	**1,225**	**1,120**	**1,220**	**1,120**	**1,220**	**780**	**480**	**380**
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 7-48 Expenditure on Protection Relays
($K in constant prices)

[40] 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.

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 in the short term to provide the automatic load control function until an alternative system is implemented.

The SCADA system is used for real time monitoring of system status and to provide an interface to remotely operate the network. SCADA can monitor and control the operation of 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 primary equipment in real time;
- Graphically display equipment outages on a dynamic network schematic; and
- Transmit local system alarms to the control room for action.

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

The most common communication links are copper pilot and fibre optic cables. Typically the copper pilots are WELL owned while most of the fibre links are under lease agreements.

WELL has two NCRs at separate sites, with one set up as a disaster recovery site. These sites are interconnected via the Transmission Control Protocol/Internet Protocol (TCP/IP) network.

An age profile of SCADA RTUs is shown in Figure 7-33.

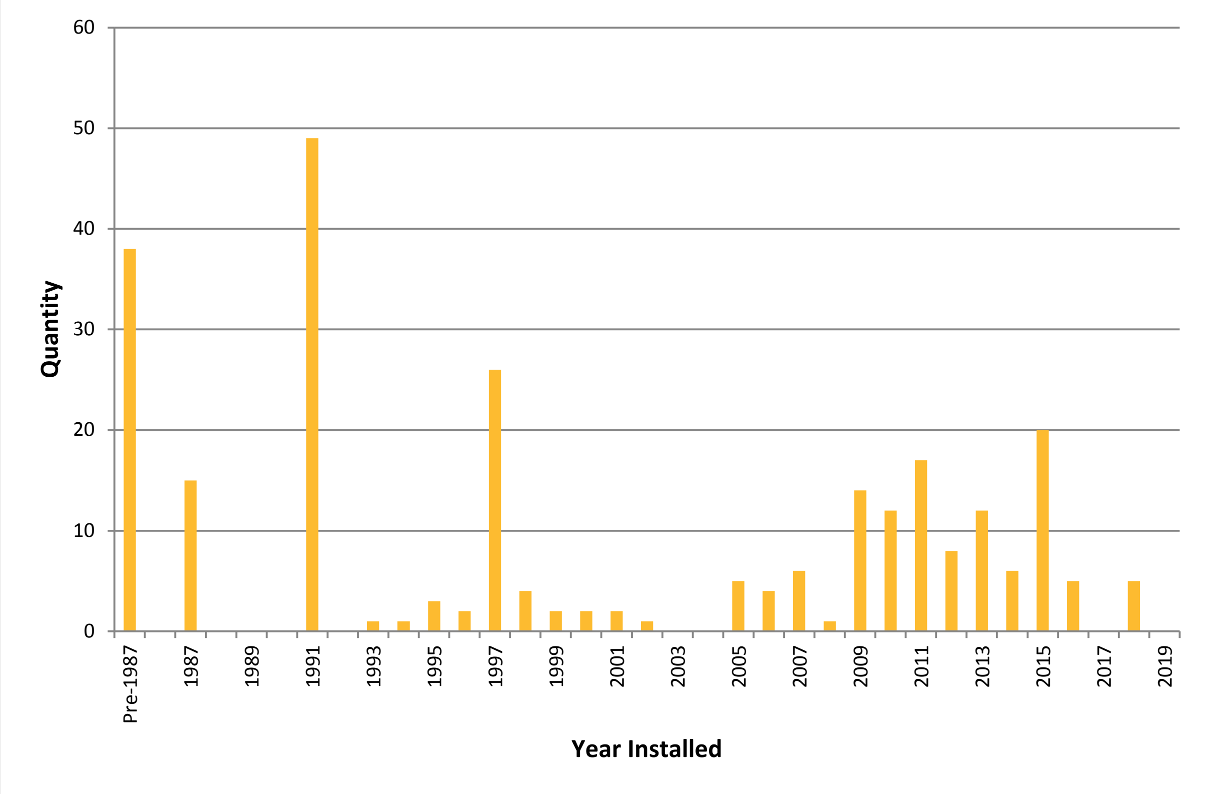


Figure 7-33 Age Profile of SCADA RTUs

To date, WELL has approximately 250 SCADA provisioned sites and is made up of RTU's 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 self-diagnostics 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.

C225 RTU

There are 12 C225 RTUs in service on the network. Power supply failure is the most common failure mode with around one failure a year. Spares are at a central location and repairs are carried out where possible. These RTUs are being replaced in conjunction with Zone RTU and protection upgrades, and the redundant units are held as spares.

C5 RTU

There are six C5 RTU's in service at very small distribution substations. They are no longer manufactured and are difficult to repair, so as they fail they are interchanged with modern alternatives.

Dataterm RTU

There are two of these in service on the network, including one at a Zone Substation. These RTU's have an inherent design flaw in the analogue card, which, over time, causes the analogues to "jump." This is repairable with the replacement of reed relays on the analogue card. These units are being replaced with Foxboro SCD5200 RTUs as zone substations are upgraded and moved onto the IP network.

Miniterm RTU

There are 48 of these in service on the network. These units fail at the rate of approximately two a year due to board level IC failure, with replacement ICs gradually becoming harder to source. These RTU's cannot be directly replaced by current technology however spare units are becoming available as a result of the switchgear replacement works. There is no active programme for replacing these but replacement occurs in conjunction with substation switchgear replacements, or where the site is regarded as high criticality.

Common Alarms

There are 38 of these systems in service on the network. These are a custom-built device, placed in minor "ringed" distribution substations to give an indication back to the NCR of a tripping event. They are prone to failure and there are no spares. On failure, the units are replaced by current technology such as a low cost RC02 RTU which is widely used on the network.

Cisco 2811 Routers

There are 20 Cisco 2811 routers in service, located in distribution substations connected to the TCP/IP network. These devices are no longer supported by the manufacturer and replacement parts cannot be purchased. There are no concerns about the performance of the equipment but where expansion is required, for example for the addition of VOIP interface cards, the 2811 router is replaced with its modern equivalent and returned to stock as a spare.

Siemens PAS

These units are at end of life and the replacement of these PAS units is planned to be undertaken in conjunction with standard RTUs. There are two Siemens Power Automation System (PAS) units that act as a protocol converter between the Siemens IEC61850 field devices located at three sites and the DNP3.0 SCADA master station. Stage 1 of the PAS replacement project was completed in 2016/2017 which provisioned the installation of new RTU's. Stage 2 will continue and encompass the remaining work to retire the PAS units from service.

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 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 using 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 GXP protection upgrades and zone substation switchgear replacement projects. There is currently no programme to replace RTUs at distribution substations as these sites generally have a lower risk profile than GXPs and Zone Substations and replacement can occur upon failure of the RTU. However an RTU upgrade will be scheduled when a specific risk is identified. In addition, sites where switchgear is upgraded may also have an RTU upgrade. These are incorporated as part of the switchgear replacement project and the need for an RTU replacement is evaluated on a case-by-case basis.

Copper pilot cables are repaired on failure. When the business case for new digital communication equipment requires a higher level of service, then copper pilot replacement with fibre optic cable is determined on a case-by-case basis.

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

- Zone RTU Replacement Programme;
- Common Alarm Replacement Programme;
- SCADA Radio Replacement; and
- End of Life RTU Replacement (Reactive).

Expenditure Summary for SCADA and Communications Assets

Table 7-49 details the expected expenditure on SCADA and communications assets by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Zone RTU Replacement Programme	600	600	600	600	300	-	-	-	-	-
Common Alarm Replacement Programme	225	225	225	225	225	225	225	225	225	225
Tier 2 RTU Replacement	-	100	100	100	-	-	-	-	-	-
Tier 3 Radio Comms Development	40	100	-	-	-	-	-	-	-	-
Siemens PAS Replacement	50	-	350	-	-	-	-	-	-	-
Reactive Capital Expenditure	100	100	100	100	100	100	100	100	100	100
Capital Expenditure Total	**1,015**	**1,125**	**1,375**	**1,025**	**625**	**325**	**325**	**325**	**325**	**325**
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 7-49 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 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 its mobile generators at its corporate office while others are used to reduce the impact of outages on consumers.

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 Regulators (AVR's) to control the power transformer tapchanger. Several sites have been identified as having AVR's which are no longer supported by suppliers.

A study is to be undertaken in 2019 to consider a replacement strategy for mature AVRs.

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 7-34.

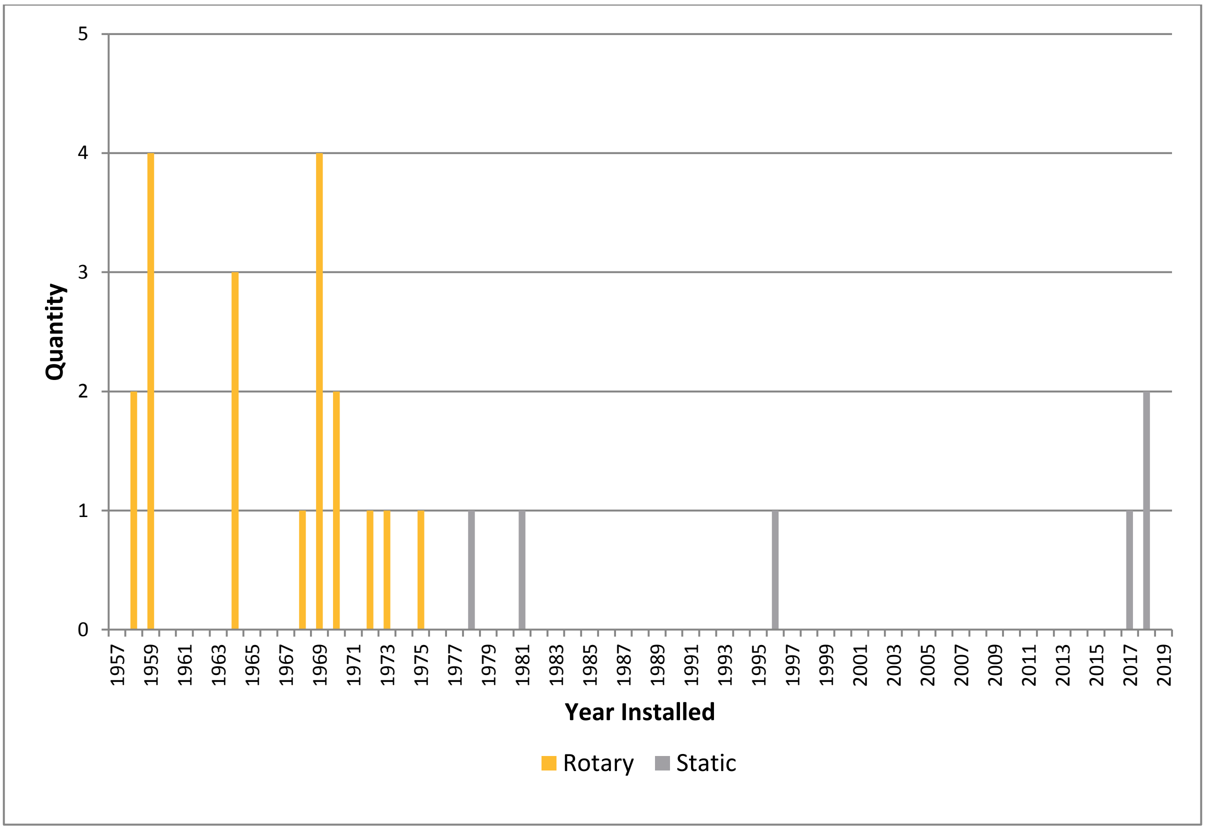


Figure 7-34 Age Profile of Ripple Plant

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 consumer receivers. As such, the full end-to-end testing of the ripple system is very 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 7-50 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 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.

LC 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.

LC PLC

The Load Control Programmable Logic Controller's (PLC) 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.

Strategic Spares

The spares held for load control plant is shown in Table 7-51.

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 7-51 Spares Held for Load Control Plant

Expenditure Summary for Other Network Assets

Table 7-52 details the expected expenditure other network assets by regulatory year.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Load Control PLC Replacement	-	40	60	60	60	60	60	60	80	-
Reactive Capital Expenditure	200	200	400	400	400	400	400	400	400	400
AVR Trial Project	85	-	-	-	-	-	-	-	-	-
Capital Expenditure Total	**285**	**240**	**460**	**460**	**460**	**460**	**460**	**460**	**480**	**400**
Preventative Maintenance	70	68	68	68	68	68	68	68	68	68
Corrective Maintenance	1,139	909	615	306	312	185	185	185	185	185
Operational Expenditure Total	**1,209**	**977**	**683**	**374**	**380**	**253**	**253**	**253**	**253**	**253**

Table 7-52 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 2019-2029

The total projected capital budget for asset replacement and renewal for 2019 to 2029 is presented in Table 7-53. This includes provision for replacements that arise from condition assessment programmes during the year. For the later years in the planning horizon, these projections are less certain in nature. Whether they proceed will depend on the risks to the network and the risks relative to other asset replacement projects. Should the consequence of failure increase, or the asset deteriorates faster than expected, then renewal may need to be brought forward. Conversely, should the risk level decrease then the project may be able to be deferred until later in the planning period or an alternative found.

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	350	350	350	350	350	3,350	2,850	1,850	1,850	350
Zone Substations	3,250	2,550	1,550	2,300	300	300	300	300	300	300
Distribution Poles and Lines	8,050	8,155	8,260	8,765	9,171	9,575	10,811	10,841	10,873	10,905
Distribution Cables	300	950	750	1,950	1,000	1,750	1,750	3,250	3,250	5,250
Distribution Substations	2,100	1,850	2,213	2,311	3,500	3,500	3,500	3,500	3,500	3,500
Distribution Switchgear	3,178	3,091	3,450	1,835	3,350	3,850	3,850	3,850	3,850	3,850
Other Network Assets	1,983	3,126	3,660	3,205	2,905	2,505	2,605	2,165	1,884	1,705
Total	**19,211**	**20,072**	**20,233**	**20,716**	**20,576**	**24,830**	**25,666**	**25,756**	**25,507**	**25,860**

Table 7-53 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 7-54. This budget is relatively constant, and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	116	116	116	116	116	114	114	114	114	114
Zone Substations	272	261	271	266	271	261	271	291	266	266
Distribution Poles and Lines	439	437	434	433	431	429	428	427	428	428
Distribution Cables	200	200	200	200	200	200	200	200	199	200
Distribution Substations	635	635	635	635	635	635	635	635	635	535
Distribution Switchgear	728	727	727	727	727	727	727	727	727	727
Other Network Assets	280	278	278	278	278	278	278	278	278	278
Total	**2,670**	**2,654**	**2,661**	**2,655**	**2,658**	**2,644**	**2,653**	**2,672**	**2,647**	**2,548**

Table 7-54 Preventative Maintenance by Asset Category ($K in constant prices)

The forecast corrective maintenance expenditure by asset category is shown in Table 7-55. This excludes capitalised maintenance, which is instead incorporated into the Asset Renewal and Replacement (ARR) expenditure forecast in Table 7-56. 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	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	265	266	268	270	273	274	216	172	172	172
Distribution Poles and Lines	824	763	764	858	866	874	880	880	880	880
Distribution Cables	575	575	575	575	575	575	575	575	573	563
Distribution Substations	1,727	1,694	1,835	1,863	1,907	1,955	1,960	1,829	1,920	1,922
Distribution Switchgear	688	689	690	691	693	694	695	759	696	696
Other Network Assets	1,244	1,014	720	411	417	290	290	290	289	290
Total	**5,323**	**5,001**	**4,852**	**4,668**	**4,731**	**4,662**	**4,616**	**4,505**	**4,530**	**4,523**

Table 7-55 Corrective Maintenance by Asset Category ($K in constant prices)

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
ARR Opex	818	818	818	818	818	818	818	818	818	818

Table 7-56 Asset Renewal and Replacement Opex ($K in constant prices)

7.6.1 Reliability, Safety and Environmental Programmes for 2019-2029

Asset management expenditure that is not directly the result of asset health drivers is categorised into quality of supply and other reliability, safety and environmental expenditure. Quality of supply projects target the worst performing feeders. Other reliability, safety and environmental projects includes the BAU seismic programme. The total projected capital budget for these categories is presented in Table 7-57.

Programme	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Worst Performing Feeders	1,571	2,107	1,592	1,717	1,413	1,413	1,455	1,499	1,544	1,590
Total Quality of Supply	**1,571**	**2,107**	**1,592**	**1,717**	**1,413**	**1,413**	**1,455**	**1,499**	**1,544**	**1,590**
Seismic Programme[41]	2,770	470	500	500	650	-	-	-	-	-
Total Other Regulatory, Safety and Environment	**2,770**	**470**	**500**	**500**	**650**	**-**	**-**	**-**	**-**	**-**

Table 7-57 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 7-58 and 7-59. For clarity, the operational expenditure forecast does not include non-maintenance related operational expenditure. Service interruptions and emergency maintenance can only be forecast and reported at a system level as the Field Service Agreement defines the rates for fault response services at a total level and not further broken down into asset category detail levels.

Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Asset Replacement & Renewal	19,211	20,072	20,233	20,716	20,576	24,830	25,666	25,756	25,507	25,860
Reliability, Safety & Environment (other)	2,770	470	500	500	650	-	-	-	-	-
Quality of Supply	1,571	2,107	1,592	1,717	1,413	1,413	1,455	1,499	1,544	1,590
Subtotal - Capital Expenditure on Asset Replacement Safety and Quality	**23,552**	**22,649**	**22,325**	**22,933**	**22,639**	**26,243**	**27,121**	**27,255**	**27,051**	**27,450**

Table 7-58 Asset Management Capital Expenditure Forecast ($K in constant prices)

[41] Note that this expenditure does not include the Seismic Strengthening work covered by the SCPP which is covered in Section 11.

Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Service interruptions & emergency maintenance	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836
Vegetation management	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815
Routine & corrective maintenance and inspection maintenance	9,948	9,963	9,963	9,963	9,963	9,963	9,963	9,963	9,963	9,963
Asset replacement & renewal maintenance	818	818	818	818	818	818	818	818	818	818
Subtotal - Operational Expenditure on Asset Management	**16,417**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**

Table 7-59 Asset Management Operational Expenditure Forecast

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Section 8

Network Development

8 Network Development

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 are expecting.

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 is insufficient 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 forecast;
- An overview of the Network Development and Reinforcement Plan (NDRP);
- Network development plans for the Southern, Northwestern and the Northeastern areas; and
- Customer initiated projects and relocations.

8.1 Network Planning Policies and Standards

The purpose of these policies and standards is to ensure the network delivers the service levels 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 (sub transmission criteria) and Table 8-2 (distribution criteria).

The security criteria are consistent with industry best practice[42] 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 not be able to be backfed, when a fault occurs during peak demand times. This is more cost-effective than removing the small risk altogether.

The WELL sub transmission 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 sub transmission 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, a brief interruption to consumers following a sub transmission or transformer fault, while the bus tie is closed, 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.

Sub-transmission

The length of time (defined as a percentage) when the sub-transmission 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.

[42] *Guide for Security of Supply*, Electricity Engineers' Association, August 2013.

Table 8-1 shows the applicable security criteria for the sub transmission network.

Type of Load	Security Criteria
CBD	N-1 capacity[43], for 99.5% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Mixed commercial / industrial / residential substations	N-1 capacity for 98% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Predominantly residential substations	N-1 capacity for 95% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.

Table 8-1 Security Criteria for the Sub Transmission Network

Distribution

Table 8-2 shows the applicable security criteria for the distribution network.

Type of Load	Security Criteria[44]
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.

Table 8-2 Security Criteria for the Distribution Network

Basis for the criteria

While the reliability of WELL's distribution system is high, notwithstanding the difficult physical environment in which the system must operate[45], 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

[43] A brief supply interruption of up to five minutes may occur following an equipment failure while the network is reconfigured.

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

[45] 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.

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. 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 the table 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.

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

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

Sub transmission 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 400 V 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.

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 less 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 subdivision.

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 the deferral of investment, 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.

8.1.9 Impact of Distributed Generation

The magnitude of small distributed generation currently installed within the network is relatively low[46] 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 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. The new AS/NZS 4777 standard is expected to be accepted into the regulations in 2019, following which WELL will update its standards. This will use the EEA "Guideline for the Connection of Small-Scale Inverter Based Distributed Generation" as a template.

Figure 8-1 Example of Distributed Generation[47]

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;

[46] Installed capacity, excluding standby generation and Mill Creek (connected at 33 kV), is only 15.8MVA, or 0.3% of the system demand.

[47] Photo supplied by Meridian Energy.

- 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

Asset capacity is 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). For operational and planning purposes, the cyclic capacities are used;
- Sub transmission Cables/Lines – Thermal conductor capacity is determined through CYMCAP modelling, considering the effect of soil resistivity, the prospective load profile and resulting thermal inertia, mutual heating due to adjacent conductors and configuration of installation. Soil and ambient temperature variations between seasons are also allowed for, providing a set of normal, cyclic and emergency ratings. For operational and planning purposes, the cyclic ratings are used;
- Sub transmission Circuit Capacity – This is determined based on the lowest rated component of the sub transmission circuit, i.e. a transformer may be rated to 36MVA while the supplying sub transmission cable is only capable of 21MVA and 17MVA during winter and summer respectively. Thus the effective rating of the sub transmission circuit is limited to the seasonal rating of the sub transmission cable; and
- 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.
- 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 2019 to 2029

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. This reflects a decoupling between the overall volume of energy consumed and the peak demand. There is also a strong correlation between peak demand and climatic conditions. Generally, demand peaks within the Wellington Region are driven by winter temperatures on the coldest days.

While the overall 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 Sep to 1 Oct in the following year;
2. The average growth rate over the last 5 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. Twelve 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 8-2.

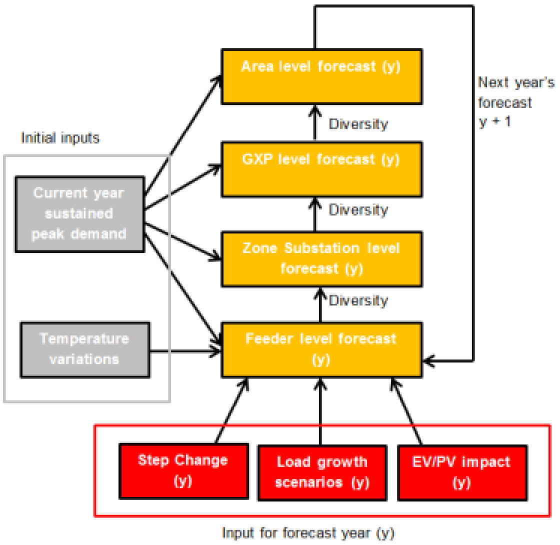


Figure 8-2 Demand Forecasting Methodology

This model is used to determine when sub transmission and feeder level constraints are likely to occur and provides an annual maximum demand that can be used in load flow modelling.

At the sub transmission 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 sub transmission level. This is plotted against the applicable N-1 sub transmission capacity constraints to determine the sub transmission 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[48];
- 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; and
- No significant impact is assumed from disruptive technologies such as PV or distributed generation, as discussed in Section 9.
- 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;

In order to calculate the sustained peak demand, forecast is based on the following information and apply assumptions listed earlier in this section:

[48] Total amount of controllable load on average is about 9% of the peak demand, but expected to slowly decline.

- 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[49] 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[50] 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 8-3, and cover mild, average and cold winter temperature profiles. Because of the known relationship between temperature and maximum demand, these temperature profiles are used to calculate the three load scenarios. Figure 8-3 shows how the winter temperature volatility correlates with the volatility in maximum demand.

[49] Diversity factors represent the difference in times of peak demand between different sites.

[50] NZ Statistics Subnational Population Projections: 2006 (base) – 2031 (October 2012 update). Used for 10+ year forecasting.

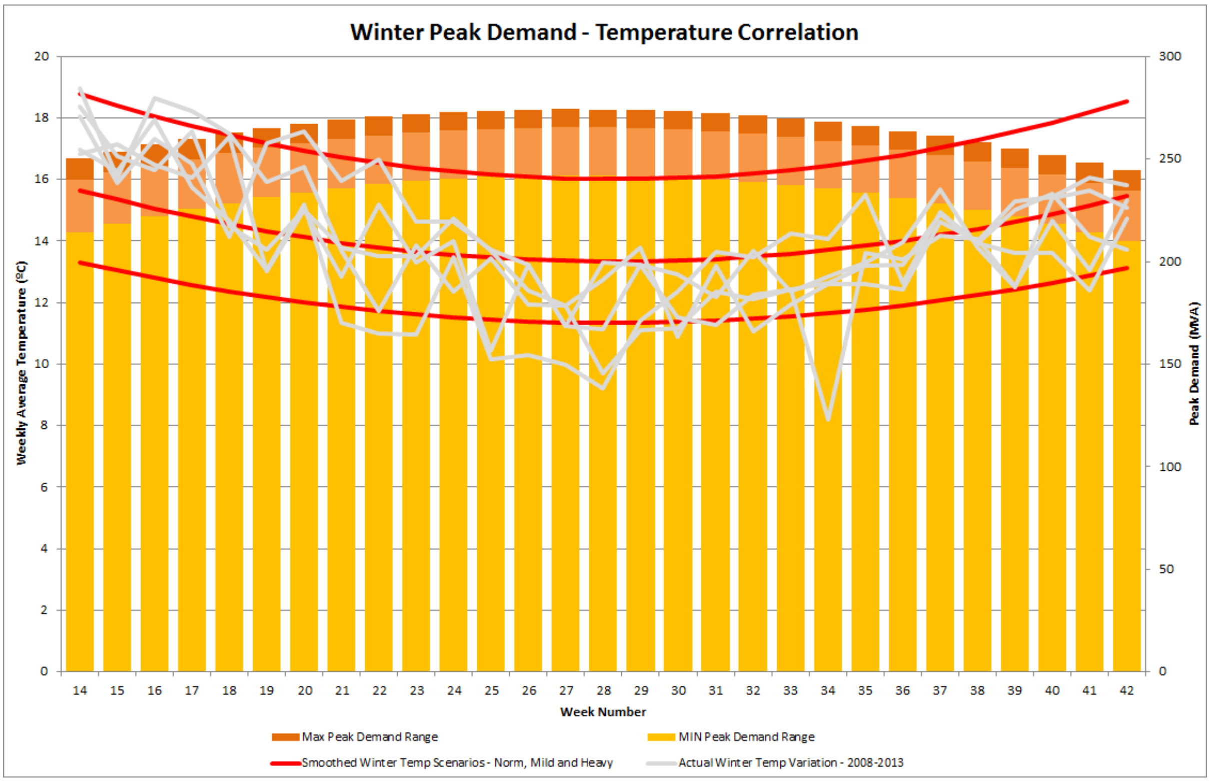


Figure 8-3 Temperature Volatility Correlation to Peak Demand Range

For example, for week 31 as shown in Figure 8-4, 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.

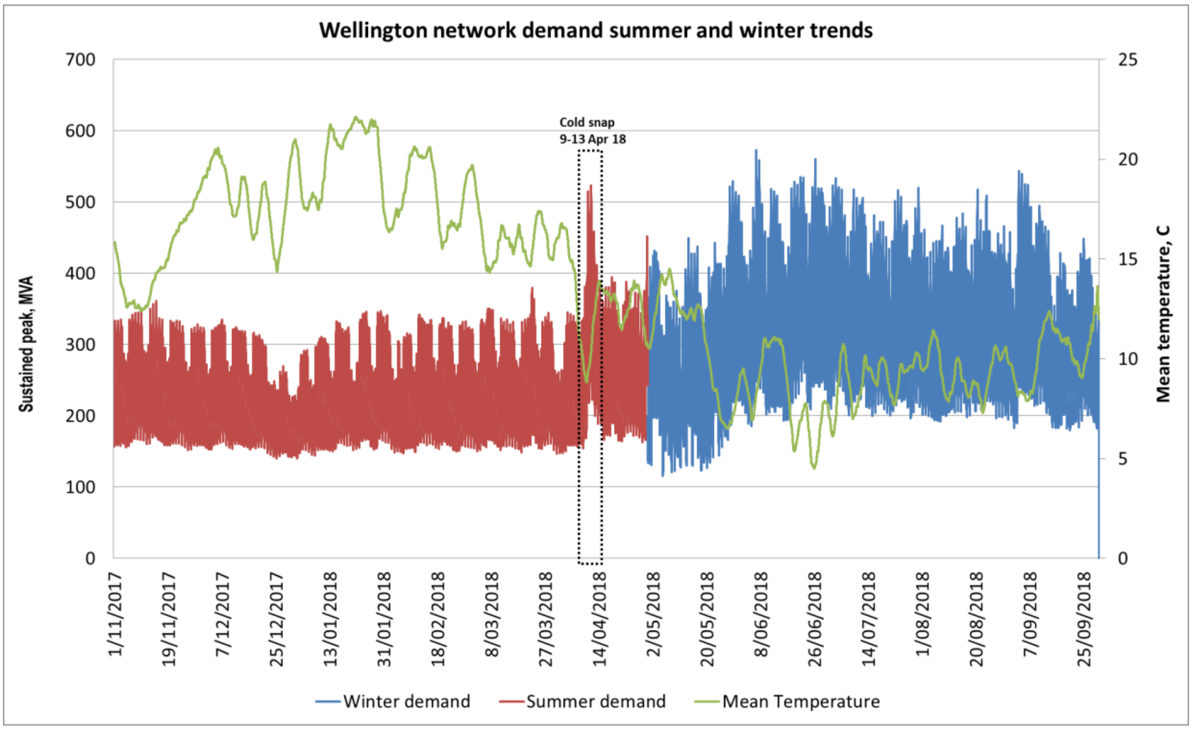


Figure 8-4 Wellington Network Summer and Winter Demand Variation

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 450kVA or ADMD capacity above 200kVA;
- 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 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.

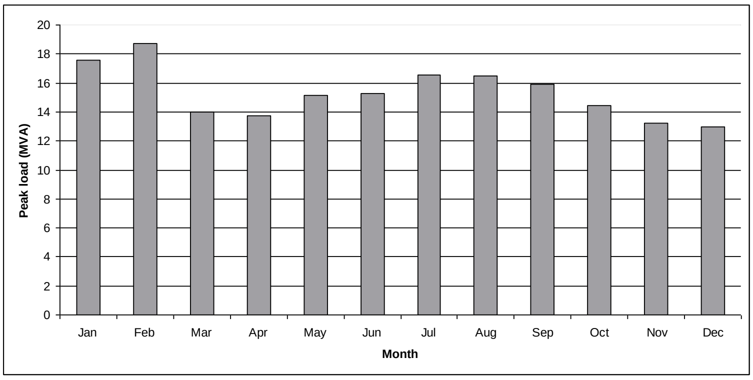


Figure 8-5 Typical CBD Monthly Peak Load Profile

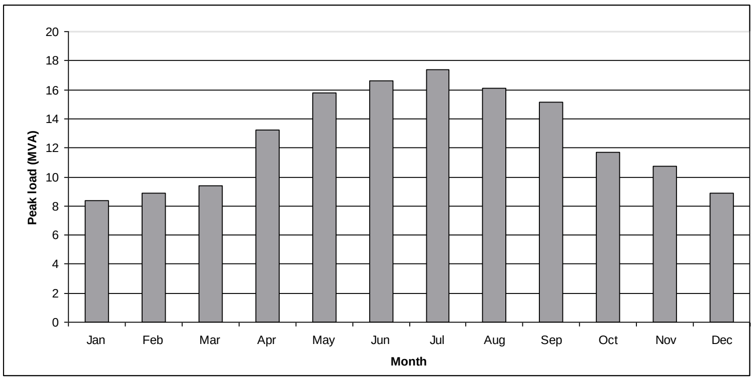


Figure 8-6 Typical Residential Monthly Peak Load Profile

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.

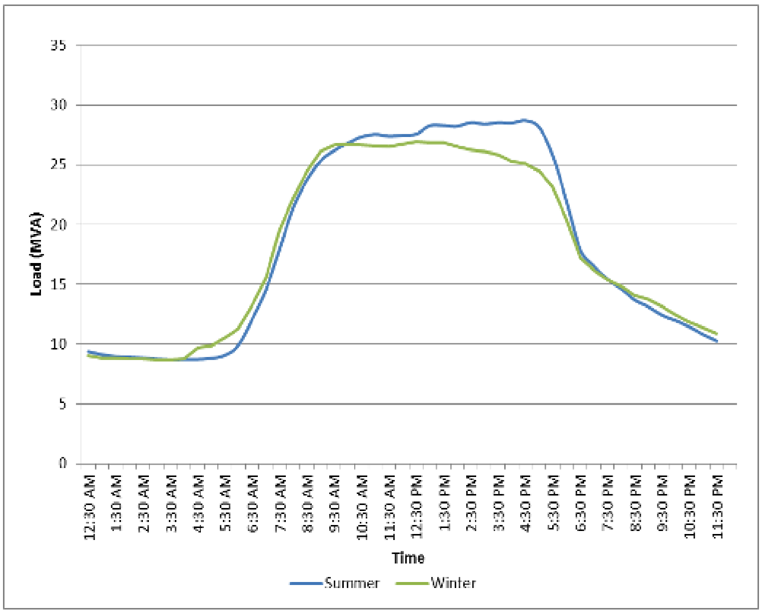


Figure 8-7 Typical CBD Zone Substation Daily Load Profile

Figure 8-8 Typical Residential Zone Substation Daily Load Profile

8.2.5 Wellington Regional Peak Demand Forecast

Accounting for the forecast scenarios, including both short and long term trends, temperature variations and step change demands, the expected system maximum demand forecast to 2028 is shown in Figure 8-9. The spread shown in the yellow band indicates the variation in both forecast assumptions and temperature. The following points apply to the forecast:

- The maximum forecast value for a particular year and season indicates the worst case scenario of high growth and colder average temperatures;
- The minimum forecast value for a particular year and season indicates the mild scenario of low to negative growth and warmer average temperatures; and
- The sustained peak demand used for planning purposes is the 60th percentile of the range of sustained peak demand values resultant from the various load growth and winter temperature scenarios per year.

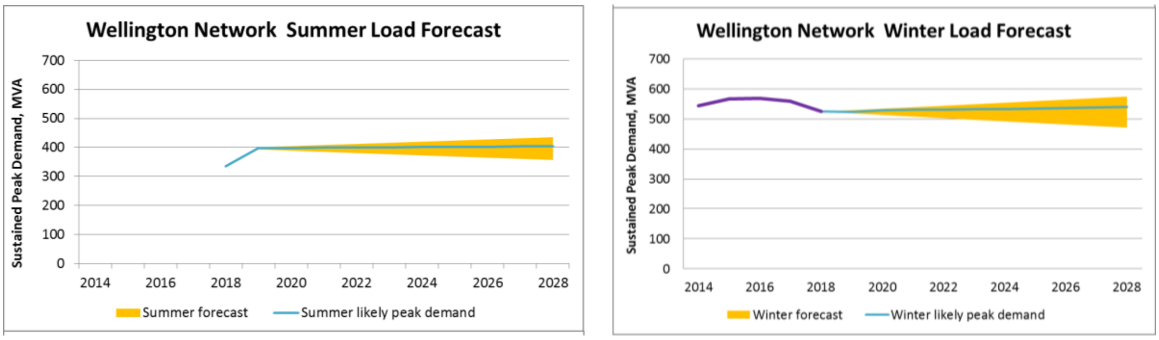


Figure 8-9 Wellington Network Load Forecast

Network	Sustained Peak Demand (MVA)										
	2018 Actual	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System Maximum Demand (MVA)	524	524	525	526	527	528	529	530	532	534	537

Table 8-4 Network Historic Demand and Forecast

Peak Time – 6 June 2018 Block 37	2018 Coincident Absolute Peak Demand (MVA)														
	Central Park	Gracefield	Haywards	Kaiwharawhara	Melling	Pautahanui	Takapu Road	Upper Hutt	Wilton	Mill Creek	Wellington Wind	Silverstream	Southern Landfill	Other Small DG	Total
2018 Coincident Peak Demand (MVA)	181	63	34	30	62	21	100	31	-8	59	1	2	0.9	1	**574**

Table 8-5 Coincident Peak Demand

The sustained peak network demand is expected to grow at a rate of 0.2 – 0.4% p.a. over the next five years. This is driven by planned step change loads such as:

- Planned residential developments in the 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; and
- Observed diversity in peak load coincidence leading to a long term reduction of overall peak demand.
- Consumer response to pricing signals

8.2.5.1 Area Sustained Peak Demand Forecasts

Figure 8-10 shows the 60th percentile of the sustained peak demand for the three areas and the aggregate demand for the Wellington region.

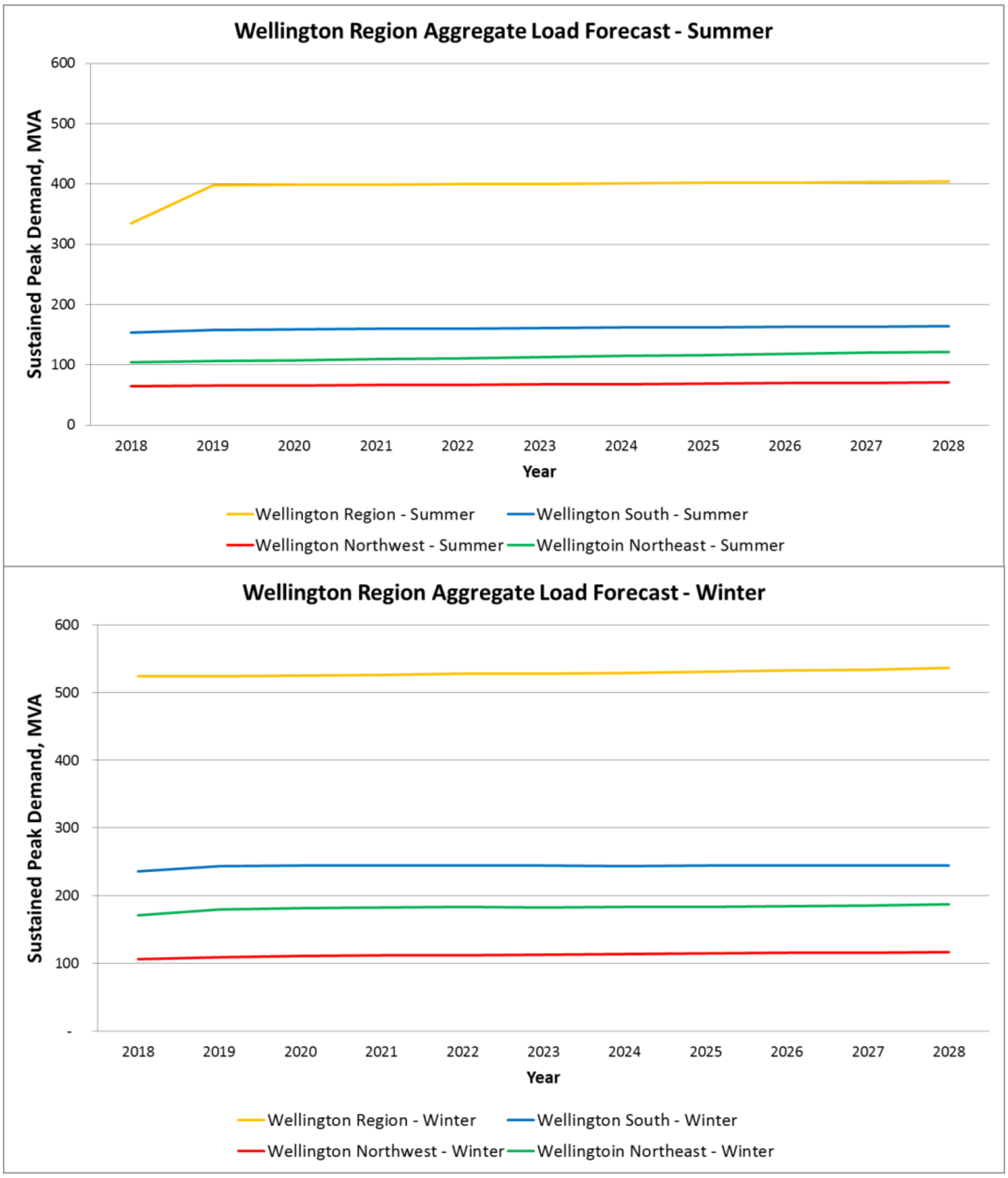


Figure 8-10 Wellington Region Aggregate Forecast

The forecasted sustained peak demand for each of the three areas of the Wellington Region shows short term peak demand growth. The Northwestern Area is forecast to experience the highest growth due to a number of residential developments expected. Overall sustained peak demand is expected to increase in the short term and level off over the long term. Overall forecast changes are relatively small and the uncertainty is high.

8.2.6 Network Area Peak Demand Forecasts

The forecast peak demand for each network area is described in more detail below. Sustained peak demand for each area is shown in Table 8-6.

Area	Sustained Peak Demand (MVA)										
	2018[51]	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Southern	236	243	244	244	244	244	244	244	244	244	244
Northwestern	106	109	111	112	112	113	114	114	115	116	117
Northeastern	171	180	182	182	183	182	183	184	184	185	187

Table 8-6 Sustained Peak Demand by Network Area

8.2.6.1 Southern Area Forecast

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 in to the regional forecast. Figure 8-11 shows the summer and winter peak forecasts for the Southern Area.

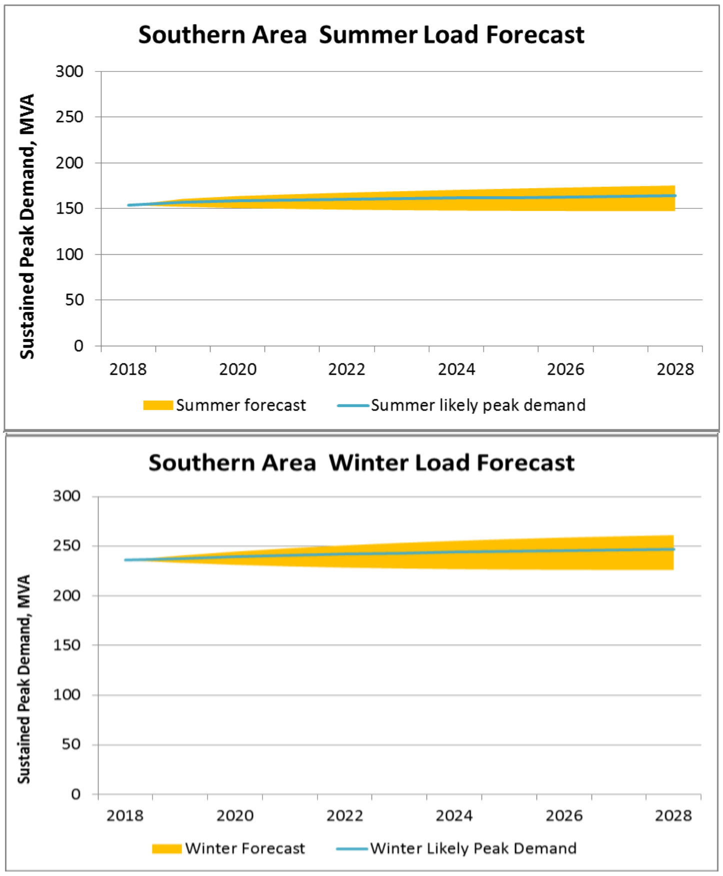


Figure 8-11 Southern Area Forecast

[51] The System Maximum Demand forecast is based on the 2018 sustained peak

Energy consumption within the Southern Area network has been flat or declining due to a general trend towards energy efficiency.

8.2.6.2 Southern - Step Change Developments

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 in place of the old 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.

8.2.6.3 Northwestern Area Forecast

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. Figure 8-12 shows a moderate increase in forecast summer peak and winter peak loading.

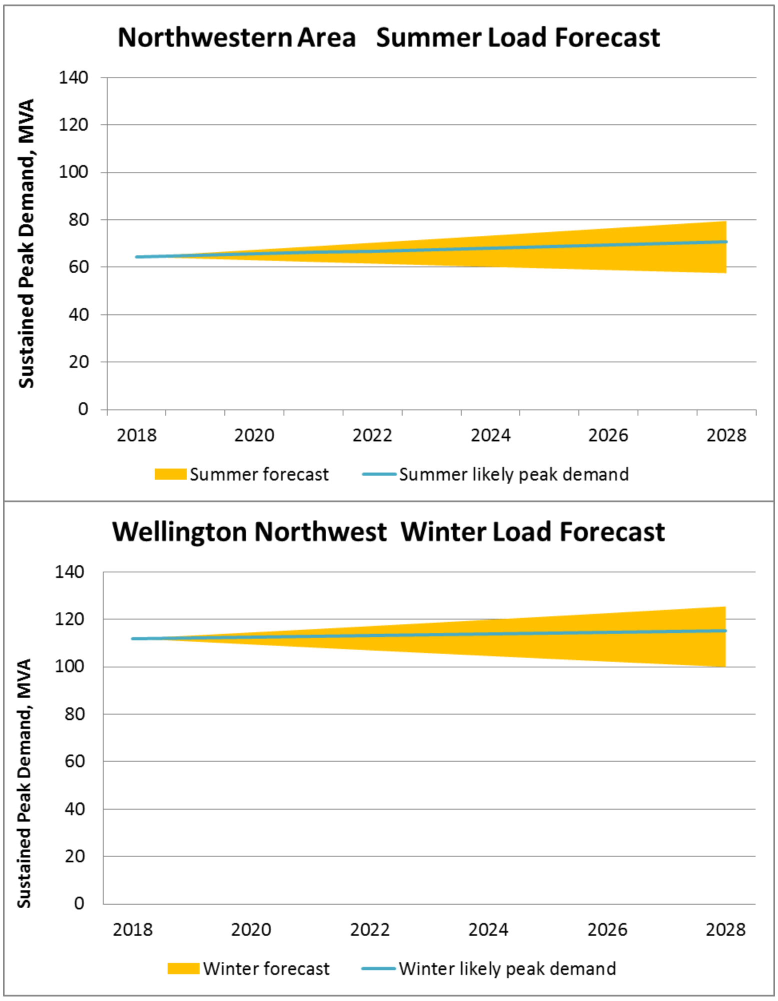


Figure 8-12 Northwestern Area Forecast

8.2.6.4 Northwestern - Step Change Developments

Expected developments in the Northwestern Area include:

- Residential and light commercial development at Upper and Lower Stebbings and Lincolnshire Farms;
- Medium density residential development is expected in the Johnsonville, Churton Park and Grenada area, particularly around the Johnsonville town centre within the next 3 years;
- Residential development in Whitby is expected to contribute 700kVA peak demand within the next 10 years;
- Residential and commercial development in the Aotea Block development area is expected to contribute 3.15 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 2019. 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 Cannons Creek 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 10 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 Pauatahhanui areas. WELL will work closely with customers on network expansion requirements for new connections and capacity upgrade projects. Refer to Figure 8-13 to 8-15 for the existing HV reticulations in the abovementioned areas.

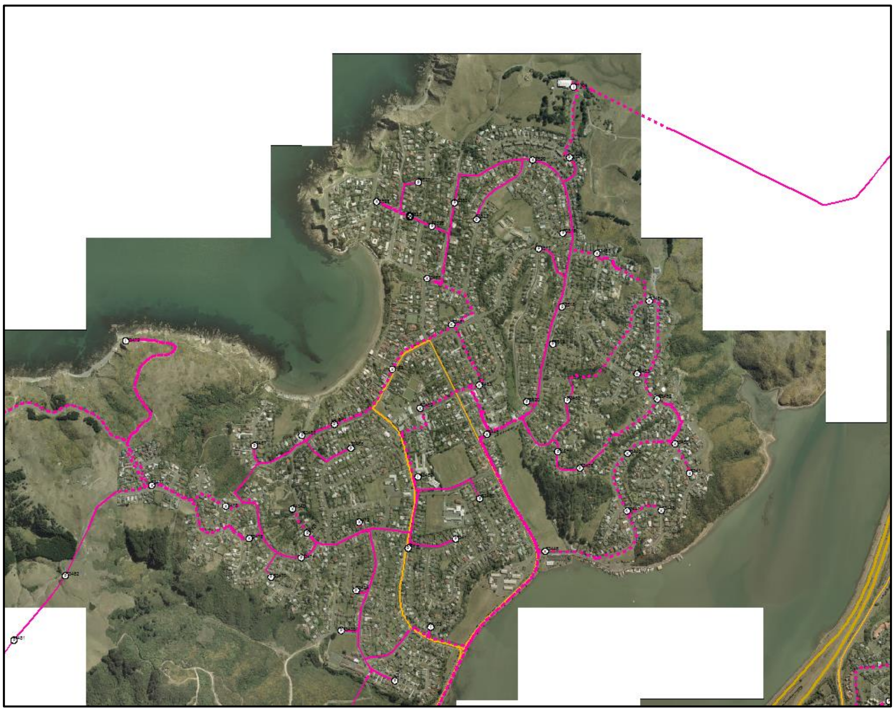


Figure 8-13 Existing HV Coverage near Titahi Bay Network Boundary

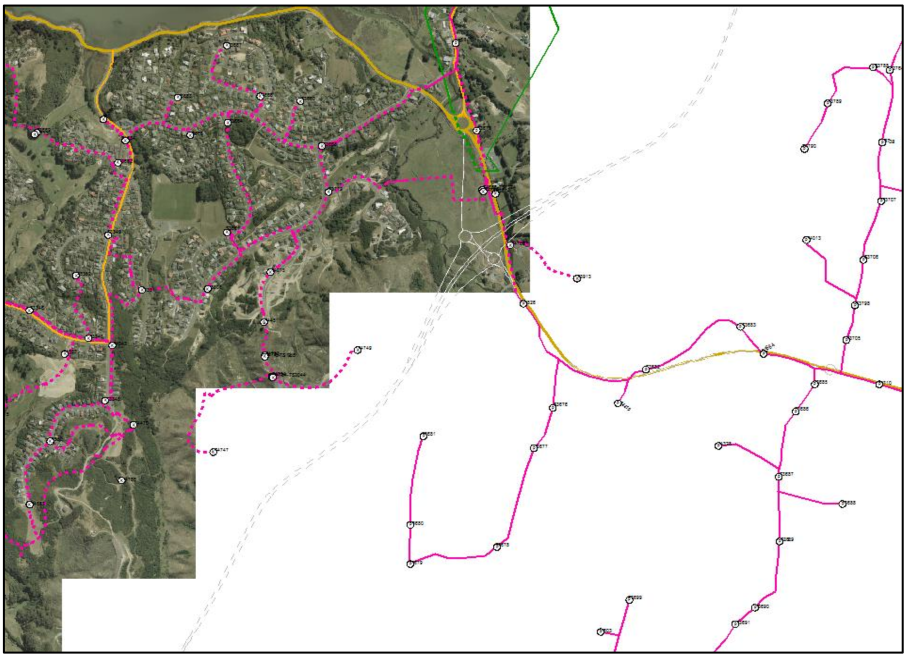


Figure 8-14 Existing HV Coverage near Pauatahanui Network Boundary

Figure 8-15 Existing HV Coverage near Plimmerton Network Boundary

8.2.6.5 Northeastern Area Forecast

Peak demand in the Northeastern Area is expected to marginally increase due to localised residential and commercial developments. This is driven by planned residential sub-divisions and expansion plans of industrial consumers in the Trentham and Maidstone zone substation supply areas. Figure 8-16 shows the forecast peak demand over the planning period.

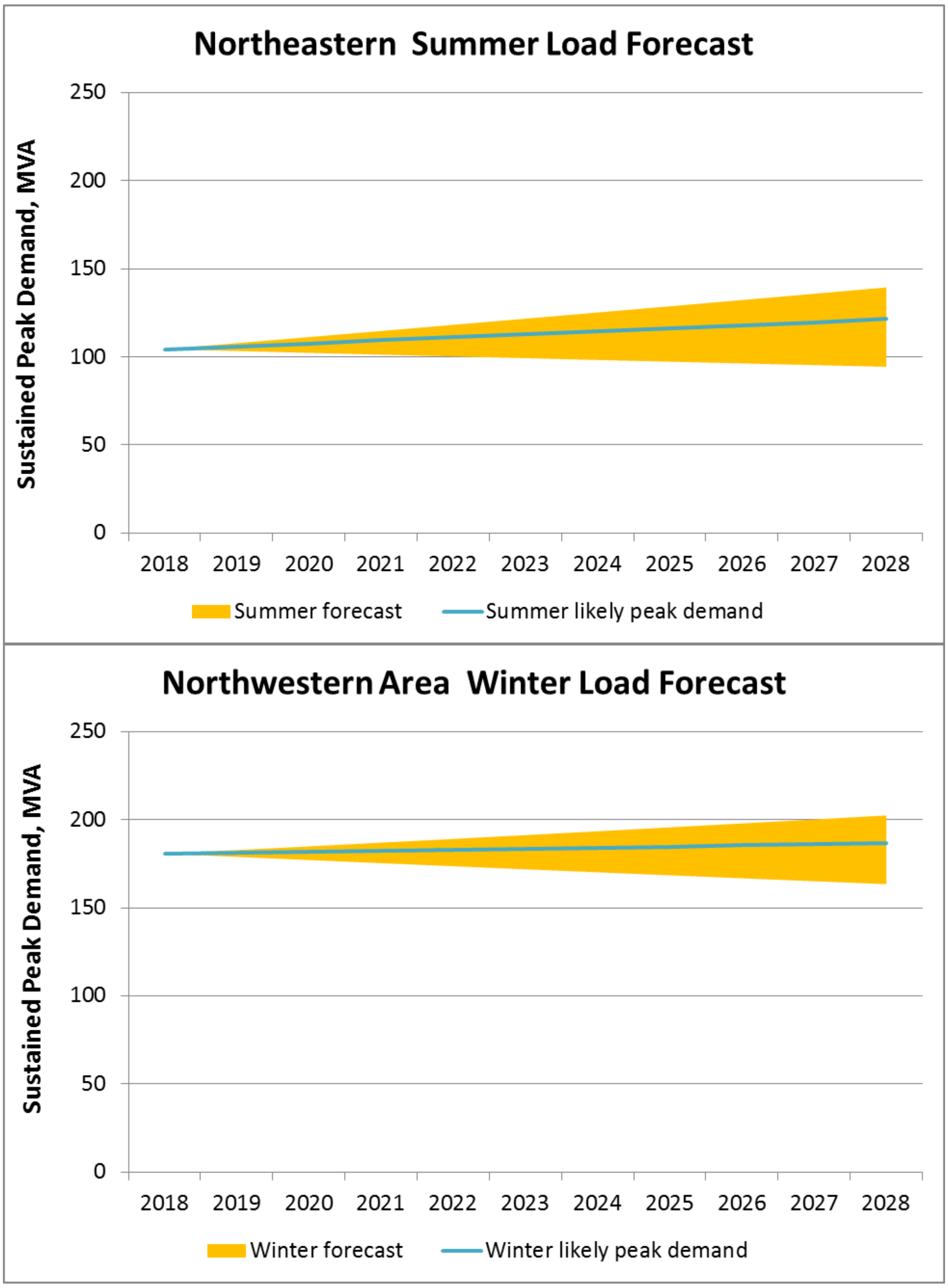


Figure 8-16 Northeastern Area Forecast

8.2.6.6 Northeastern Step Change Developments

A number of developments are likely within the Northeastern Area, confirmed either through requests received for customer connections or through information requests from developers. The majority of step change loads expected are due to expansion of industrial facilities within the Trentham area.

Expected developments in the Northeastern Area include:

- Expansion of a customer data centre facility which will involve 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. Refer to Figure 8-17 to 8-18 for the existing HV reticulations in Upper Hutt and Wainuiomata.

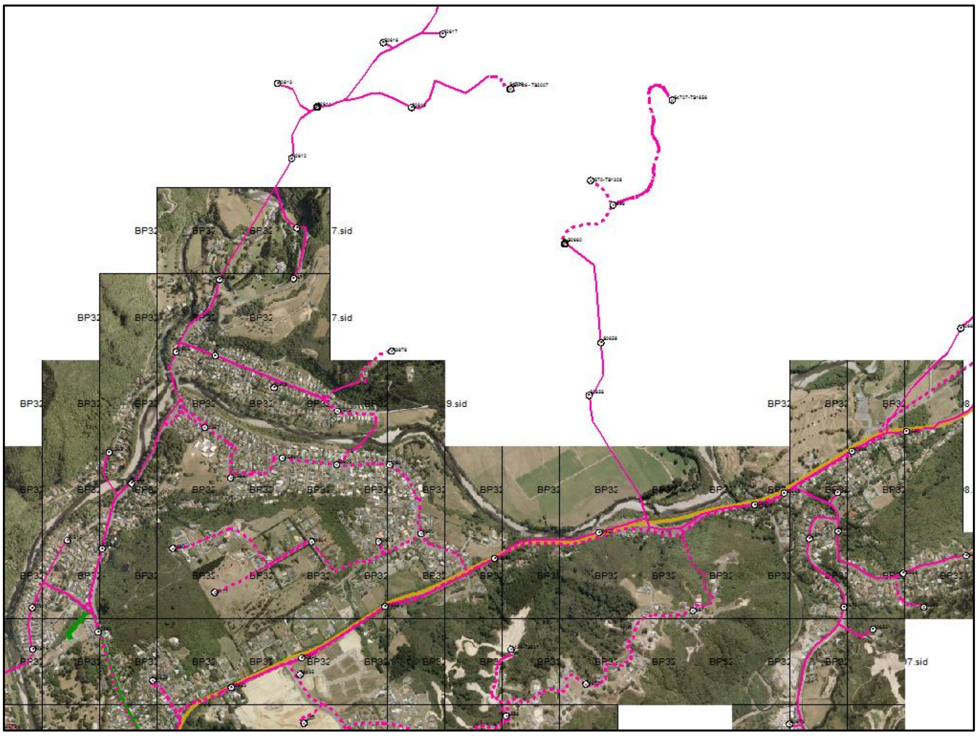


Figure 8-17 Existing HV Coverage near Upper Hutt Network Boundary

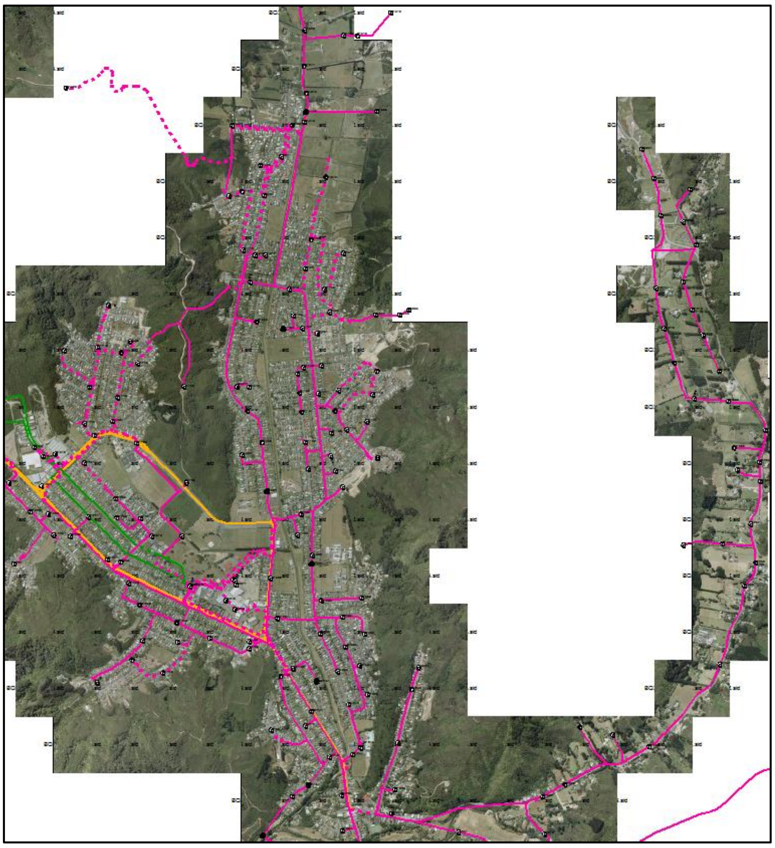


Figure 8-18 Existing HV Coverage near Wainuiomata Network Boundary

8.2.7 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 region and Table 8-8 shows the Zone substation level forecast by region. 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[52]	Actual and Forecast Sustained Peak Demand[53] (MVA)										
		2018 Actual	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Southern	Central Park 33 kV	149	154	155	155	155	155	155	155	155	155	155
	Central Park 11 kV	23	23	23	23	23	23	23	23	23	23	24
	Wilton 33 kV	43	47	47	47	47	47	47	47	47	47	47
	Kaiwharawhara 11 kV	29	29	29	29	29	29	29	29	29	29	29

[52] 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 sub-transmission and distribution planning.

[53] 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	GXP[52]	Actual and Forecast Sustained Peak Demand[53] (MVA)										
		2018 Actual	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
North-Western	Pauatahanui 33 kV	18	18	18	18	18	18	18	18	18	18	18
North-Western	Takapu Rd 33 kV	91	95	97	98	99	99	100	101	101	102	103
North-Eastern	Gracefield 33 kV	60	66	67	67	68	68	68	68	68	69	69
North-Eastern	Haywards 33 kV	14	16	16	16	17	17	17	17	18	18	18
North-Eastern	Melling 33 kV	33	34	34	34	34	34	34	34	34	34	34
North-Eastern	Upper Hutt 33 kV	30	31	31	31	31	32	32	32	32	33	33
North-Eastern	Haywards 11 kV	17	18	18	18	18	18	18	18	18	18	19
North-Eastern	Melling 11 kV	24	24	24	24	24	23	23	23	23	23	23

Table 8-7 Wellington Area GXP Level Forecast

Area	Zone	Actual and Forecast Sustained Peak Demand[54] (MVA)										
		2018 Actual	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Southern Area	Palm Grove	25.4	22.2	23.1	23.2	23.2	23.3	23.3	23.4	23.5	23.5	23.6
	Frederick St	28.2	30.1	30.3	30.1	30.0	29.9	29.8	29.7	29.6	29.5	29.4
	Evans Bay	13.5	15.6	15.5	15.5	15.4	15.3	15.2	15.1	15.0	14.9	14.9
	Hataitai	16.9	21.5	21.2	20.8	20.5	20.2	19.9	19.6	19.4	19.1	18.8
	University	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.7	19.7	19.7	19.7
	The Terrace[55]	31.4	31.6	31.8	32.0	32.2	32.4	32.7	32.9	33.1	33.4	33.6
	8 Ira St	16.3	16.4	17.0	17.0	17.1	17.1	17.1	17.2	17.2	17.3	17.3
	Nairn St	22.5	23.2	23.2	23.2	23.3	23.3	23.3	23.4	23.4	23.4	23.5
	Karori	14.1	14.3	14.2	14.2	14.2	14.2	14.1	14.1	14.1	14.1	14.1
	Moore St[16]	23.7[56]	26.7	26.8	26.8	26.9	26.9	27.0	27.1	27.1	27.2	27.3
	Waikowhai	13.1	14.2	14.1	14.1	14.1	14.0	14.0	14.0	14.0	14.0	14.0
North-Western Area	Mana	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
	Plimmerton	8.7	8.8	8.8	8.8	8.8	8.8	8.9	8.9	8.9	8.9	8.9
	Johnsonville	20.8	21.2	21. 5	21.7	22.0	22.5	22.7	23.0	23.3	23.7	24.1
	Kenepuru	11.2	12.7	14.3	14.9	15.1	15.3	15.5	15.7	15.9	16.1	16.3
	Ngauranga	9.6	9.8	9.7	9.6	9.6	9.5	9.5	9.5	9.5	9.5	9.4
	Porirua	20.9	22.3	22.6	22.8	23	23.3	23.5	23.8	24.1	24.4	24.7
	Tawa	14.3	15.0	15.0	14.9	14.9	14.9	14.8	14.8	14.8	14.8	14.7
	Waitangirua	13.2	13.4	13.4	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.3
North-Eastern Area	Gracefield	11.7	11.7	12.7	12.6	12.5	12.4	12.3	12.3	12.2	12.1	12.1
	Korokoro	19.6	19.9	20.3	20.6	21	21.4	21.8	22.1	22.5	22.9	23.4
	Seaview	13.9	14.4	14.3	14.2	14.1	13.9	13.8	13.7	13.6	13.5	13.4
	Wainuiomata	18.9	19.2	19.6	19.6	19.7	19.7	19.7	19.7	19.7	19.7	19.7
	Trentham	14.3	16	16.2	16.4	16.7	16.9	17.2	17.4	17.7	18	18.3
	Naenae	14.8	15.5	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.7	15.7
	Waterloo	15.6	15.6	15.6	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
	Brown Owl	14.7	15.3	15.3	15.3	15.3	15.3	15.3	15.4	15.4	15.4	15.4
	Maidstone	14.3	15	15.2	15.4	15.6	15.8	16	16.2	16.4	16.6	16.8

Table 8-8 Wellington Area Zone Substation Level Forecast

[54] 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.

[55] The Terrace and Moore St zone substations have a summer peak. All other stations are winter peaking.

[56] Due to the impact of the 2017 Kaikoura Earthquake, Moore Street Zone demand fell due to property damage, however this is not considered for the long term 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, sub transmission and zone substations and then distribution level investments. The GXP level discussion has been developed with reference to Transpower's Transmission Planning Report and other formal discussions with Transpower regarding their proposed development plans.

The NDRP for each network area is described in the following sections.

8.4 Southern Area NDRP

This section provides a summary of the Southern Area NDRP. It is structured as follows:

- Potential GXP developments;
- Identified sub transmission and distribution development needs and options;
- The network development plan for the planning period; and
- A summary of the expected expenditure profile.

Details of the projects currently in progress or completed in the previous year are described in Appendix C.

8.4.1 GXP Development

The Southern network is supplied from three GXPs, Central Park, Wilton and Kaiwharawhara. The transformer capacity and the maximum system demand are set out in Table 8-9.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Maximum Sustained Demand (MVA)	
			2018	2028
Central Park 33 kV	2x100 1x120	2x 108 / 112	143	149
Central Park 11 kV	2x25	29 / 30	23	24
Wilton 33 kV	2x100	103 / 110	38	42
Kaiwharawhara 11 kV	2x30	38 / 38	29	29
Total (after diversity)	-	-	**236**	**244**

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 sub transmission 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. 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. In 2019 the key focus will be selecting a preferred development option and obtaining approval from major stakeholders for detailed development.

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 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 220kV 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.

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 not exceed the firm capacity at Kaiwharawhara during the planning period.

8.4.2 Sub-transmission and Distribution Development Plans

This section describes the identified security of supply constraints and development needs for the Southern Area sub-transmission 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 sub-transmission 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	Transformer Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Sustained Peak Demand (MVA)		Date constraints are binding and season constrained	ICP counts as at 2018
		Winter	Summer		2018	2028		
Existing constraints								
Frederick St	30	23.2	19.5	Winter	28	33	Existing Winter and Summer constraint (25)	5,854
Palm Grove	24	34	32	Winter	25	24	Existing Winter constraint	9,933
The Terrace	30	34	32	Summer	31	31	Existing Summer constraint	1,714
Forecasted constraints								
Hataitai	23	22	13	Winter	17	18	2019 Summer constraint (15)	7,328
Not Constrained								
Nairn St	25	25	25	Winter	23	24	Not Constrained	5,956
Evans Bay	24	19	15	Winter	13	15	Not Constrained	4,460
University	24	25	20	Winter	20	20	Not Constrained	5,659
Waikowhai	19	21	13	Winter	13	14	Not Constrained	6,100
Moore St	30	36	31	Summer	24	27	Not Constrained	388
8 Ira St	24	21	15	Winter	16	17	Not Constrained	5,241
Karori	24	21	11	Winter	14	14	Not Constrained	6,084

Table 8-10 Southern Area Zone Substation Capacities

At the sub transmission level, WELL's planning criterion is to maintain N-1 capacity down to the 11 kV incomer level. A typical sub transmission 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 20-36 MVA range, fitted with oil circulation pumps and cooling fans to provide a higher cyclic rating; and
- 11 kV cabling from the 11 kV terminations of the transformers to the incomers on the switchboard which can potentially constrain the sub transmission circuit rating if undersized, is also considered a component of the sub transmission circuit.

The development needs for the Southern Area at the sub transmission and distribution level are outlined in the following sections.

8.4.2.1 Sub Transmission Development Needs

Sub transmission constraints can be quantified in terms of duration of potential overload and 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 zone substations that are forecast to be beyond N-1 security during the planning period are described below.

Frederick Street

The sustained peak load supplied by Frederick Street currently exceeds the cyclic N-1 capacity of the sub transmission supply cables. The constraint is due to the heating effects of the two cables being in close proximity to each other. Work was undertaken in late 2015 to mitigate most, but not all, of the constraining sections. These works have resulted in an increase in the cyclic capacity of the Frederick Street sub transmission cables, from 17/21 MVA (summer/winter cyclic rating) to 19.5/23.2 MVA. The maximum demand at Frederick Street is still in excess of the sub transmission cable capacity.

Table 8-11 illustrates the seasonal constraint levels and the minimum off load requirements on each circuit.

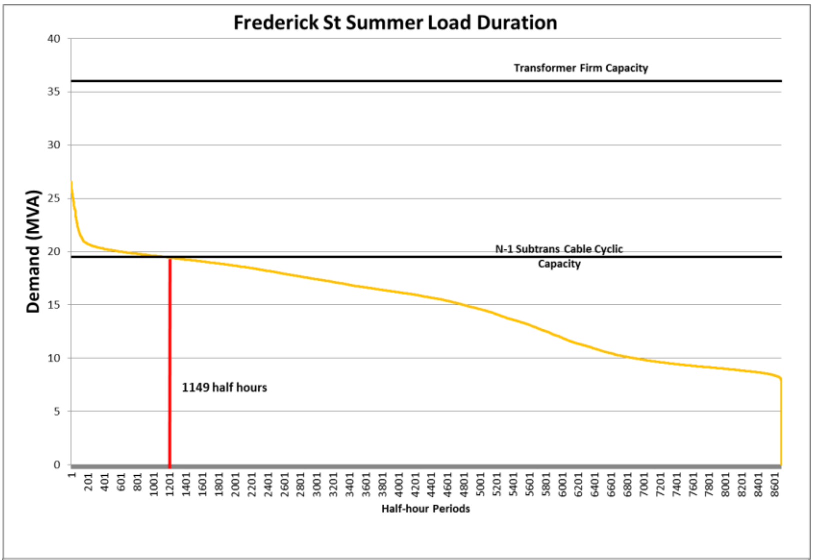
Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
Frederick St 1	Winter	23.2	28.2	5.0
	Summer	19.5	20.9	1.4
Frederick St 2	Winter	23.2	28.2	5.0
	Summer	19.5	20.9	1.4

Table 8-11 Current Frederick Street Sub transmission Constraints

Following a fault on the sub transmission 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.

Future step change loading on feeders inter-connecting with Frederick Street will reduce the available transfer capacity and post contingency offload will become difficult.

Figure 8-19 shows the load duration curve against the N-1 cyclic ratings of transformer and sub transmission cable.



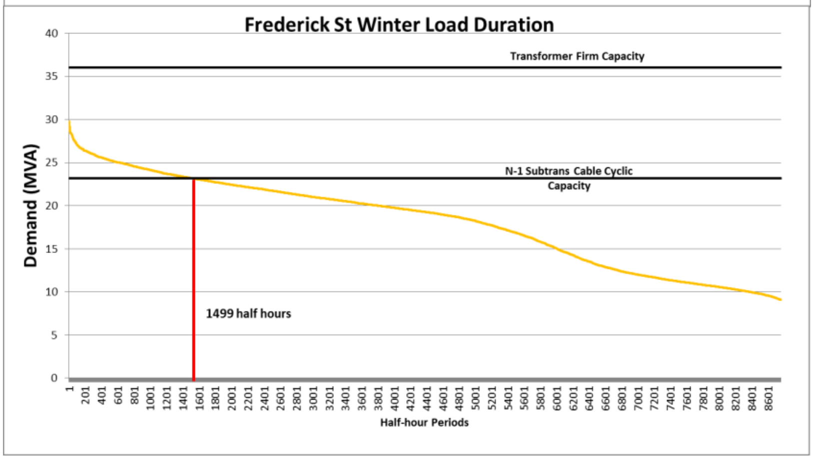


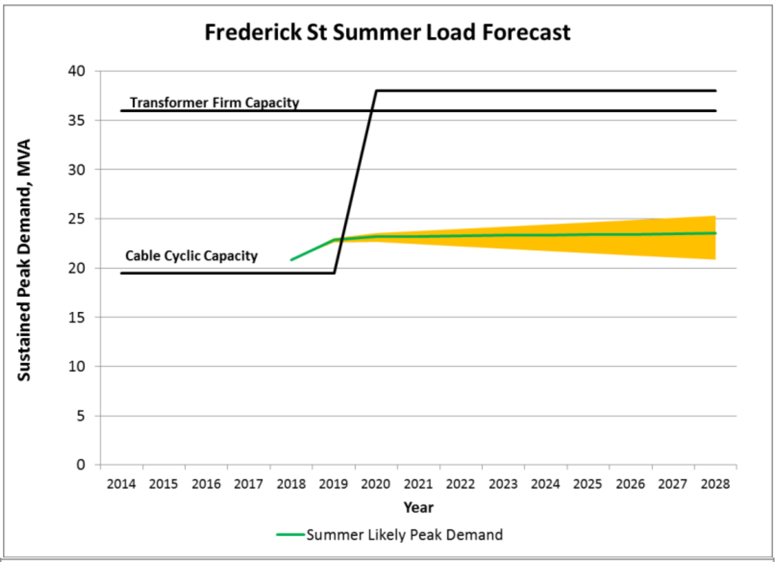
Figure 8-19 Frederick Street Load Duration Curve

The load duration curve shows the proportion of load at risk. The loading exceeds the cable's N-1 summer cyclic rating for approximately 6.6% of the time in summer and the cable's N-1 winter cyclic rating for approximately 8.6% of the time in winter. This analysis uses a load duration curve based on 30 minute periods and is higher than the sustained peak.

In 2016 the load pattern in Frederick Street was showing a greater level of constraints in summer than winter but this has changed back to a traditional level of winter constraints since 2017.

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 8-20. The sub transmission capacity constraints are plotted for comparison.

WELL is currently doing a feasibility study for the 33kV Frederick Street cable replacement project. The step change of the proposed rating based on the conceptual design is shown in the load forecast diagram, Figure 8-20. After completing this upgrade, the current constraint at Frederick Street on cable will be removed. This also allows better load sharing between Frederick Street and Terrace zone substations to defer the Terrace transformer replacement timeline.



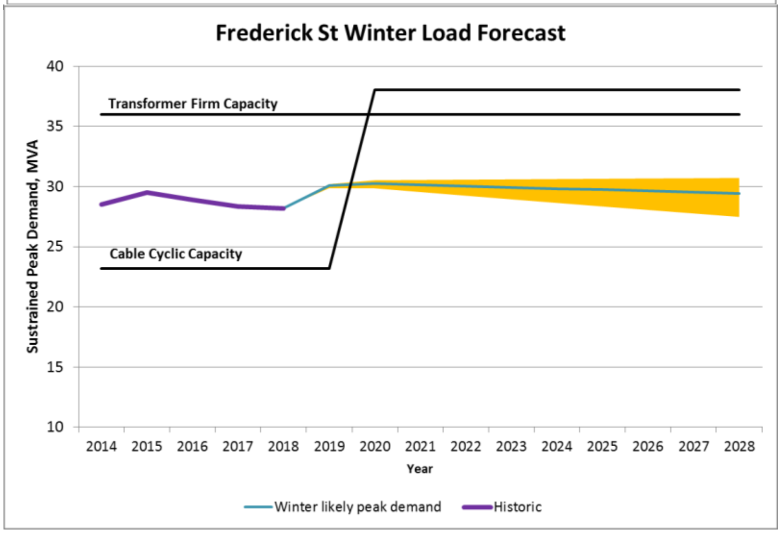


Figure 8-20 Frederick Street Load Forecast

Palm Grove

The sustained peak demand at Palm Grove currently exceeds the capacity of the two 24 MVA transformers as illustrated in Table 8-12.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
Palm Grove 1	Winter	24	25.4	1.4
	Summer	24	17.2	0.0
Palm Grove 2	Winter	24	25.4	1.4
	Summer	24	17.2	0.0

Table 8-12 Current Palm Grove Sub transmission Constraints

Following an outage of a single sub transmission 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 8-21.

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 have 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 has also indicated high level plans to expand facilities at Wellington Hospital within the planning period. The capacity and timing of these expansion plans are being worked through.

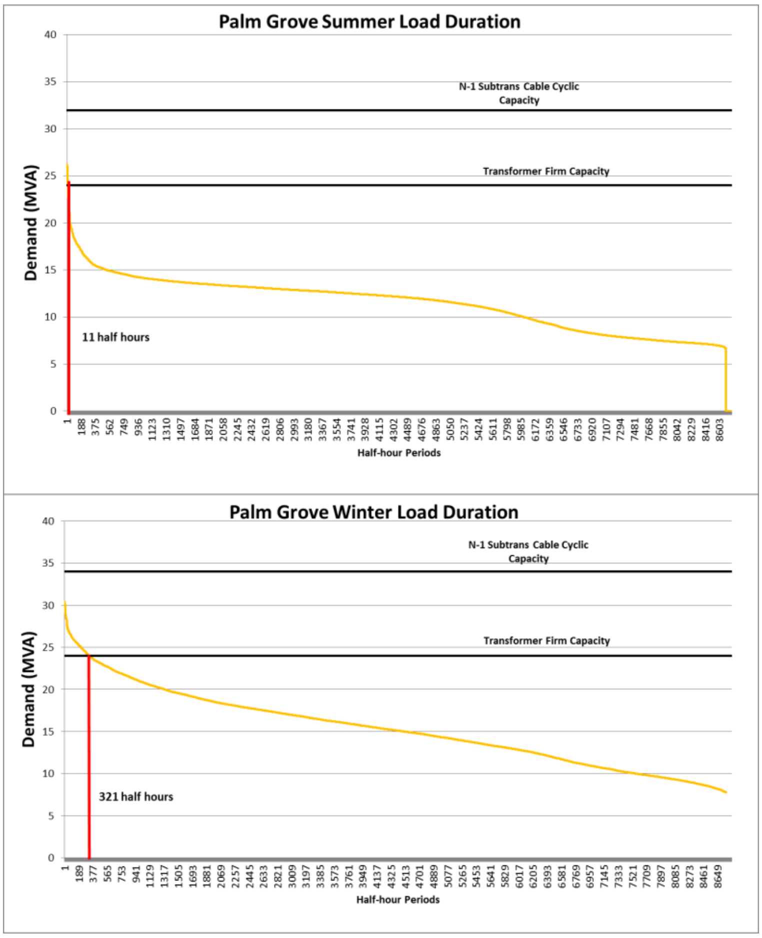


Figure 8-21 Palm Grove Load Duration

The peak demand during winter exceeds the N-1 transformer cyclic capacity for approximately 1.8% 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 8-22. The strategy is to balance the load between

Palm Grove and Hataitai via a changeover system to better utilise the spare capacity from Hataitai and defer asset replacement timeline at Palm Grove.

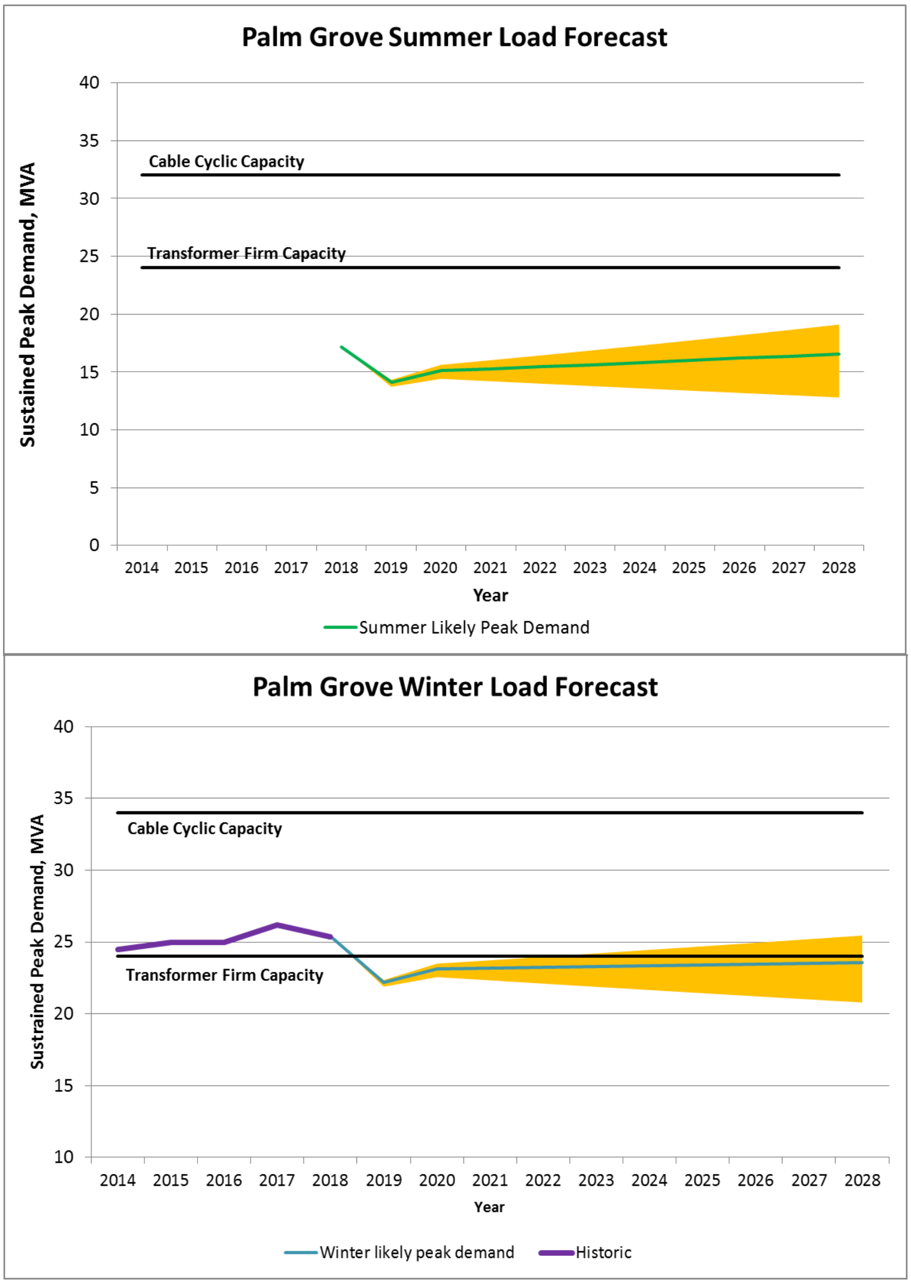


Figure 8-22 Palm Grove Load Forecast

The Terrace

The sustained peak demand at The Terrace currently exceeds the capacity of the two 30 MVA transformers as illustrated in Table 8-13.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
The Terrace 1	Winter	30	28.2	0
	Summer	30	31.4	1.4

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
The Terrace 2	Winter	30	28.2	0
	Summer	30	31.4	1.4

Table 8-13 Current The Terrace Sub transmission Constraints

The load duration curve given in Figure 8-23 shows that over the last 12 month period the loading exceeds the transformer's N-1 cyclic capacity for approximately 0.8% of the year, which is slightly above the CBD security criteria for a CBD zone substation (0.5% limit). This load duration curve is based on 30 minute periods.

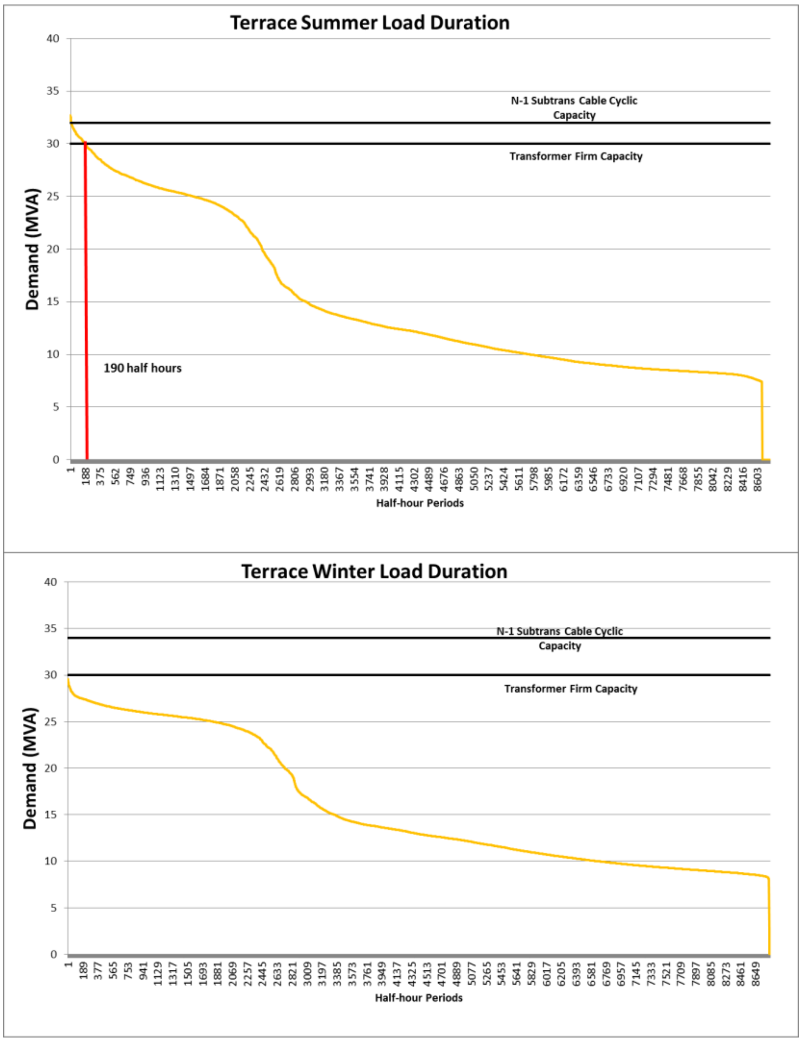


Figure 8-23 The Terrace Load Duration

The magnitude of the exceedance is expected to increase due to organic growth in the area and step change growth from new capacity connections, as shown in Figure 8-24. The forecast summer peak load is expected to exceed the 33 kV incomer cable N-1 cyclic rating by 2023 and the winter peak load is also expected to exceed the transformer capacity by 2025. A strategy to manage future loading will be confirmed when the load is confirmed. 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.

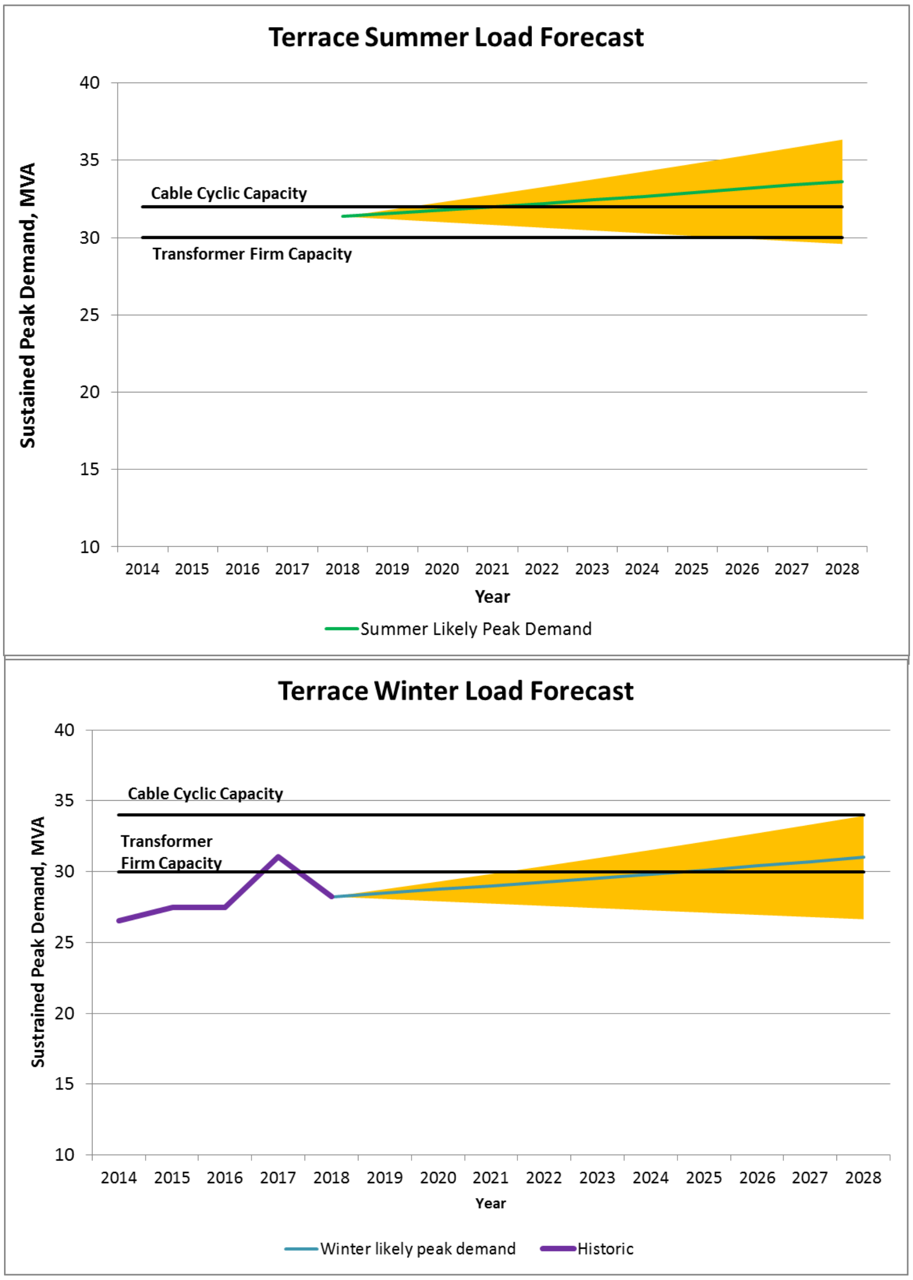


Figure 8-24 The Terrace Load Forecast

Hataitai

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 sub transmission circuits is predicted to become a constraint from 2019 if the primary supply source for Wellington Hospital is transferred from Palm Grove to Hataitai.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2022 (MVA)	Minimum off load for N-1 @ peak (MVA)
Hataitai 1	Winter	22	20.5	0.0
	Summer	13	14.6	1.6

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2022 (MVA)	Minimum off load for N-1 @ peak (MVA)
Hataitai 2	Winter	22	20.5	0.0
	Summer	13	14.6	1.6

Table 8-14 Current Hataitai Sub transmission Constraints

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. The forecasted sustained peak demand at Hataitai is shown in Figure 8-25.

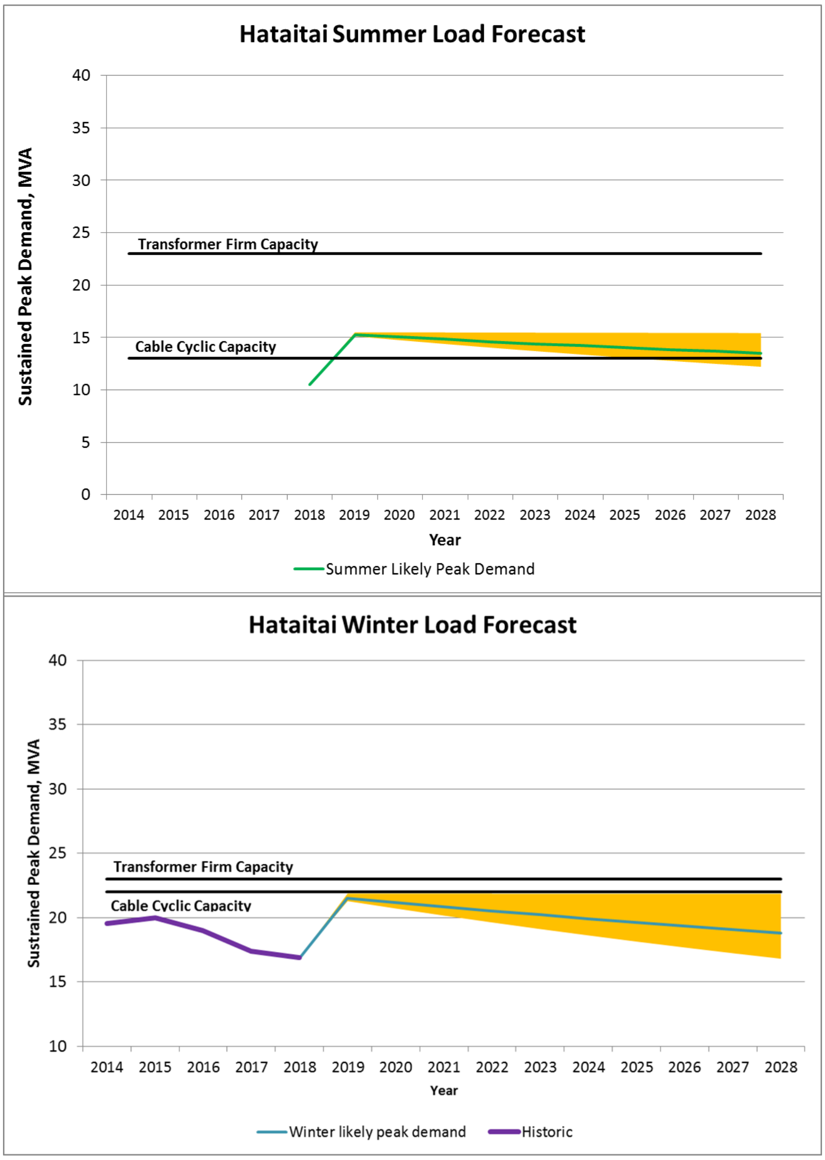


Figure 8-25 Hataitai Demand Forecast

8.4.2.2 Distribution Level Development Needs

The most critical distribution level issues are those associated with:

- Meshed ring feeders supplying a high number of consumers; and
- Links between zone substations which can be used for load transfer.

Table 8-15 shows the current and forecast loading for each feeder. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder the planned steady state control to manage any risks that might arise.

Feeder	Topology	Zone Substation	Potential Upgrade Cable Length	Present Loading	+5 years	Feeder ICP Count	Control
Current							
EVA CB2/4	2 Fdr Mesh	Evans Bay	2,202 m	65%	69%	2,753	Monitor growth
FRE CB13/14	2 Fdr Mesh	Frederick Street	921 m	65%	65%	2,465	Network augmentation
KAR CB3/6	2 Fdr Mesh	Karori	2,137 m	68%	81%	3,903	Network augmentation
KAI CB6/7/9/10	Radial sub feeder	Kaiwharawhara	3,331 m	90%	102%	2,303	Customer initiated and funded project
NAI CB11/13	2 Fdr Mesh	Nairn Street	362 m	51%	52%	2,662	Monitor Growth
NAI CB11/13	Radial sub feeder	Nairn Street	635 m	70%	72%	2,662	Monitor Growth
PAL CB8/10/12	Radial sub feeder	Palm Grove	469 m	72%	89%	5,410	Customer initiated and funded project
UNI CB8/10	2 Fdr Mesh	University	856 m	56%	63%	1,870	Network augmentation/ reconfiguration
Within Five Years							
MOO CB1/2	2 Fdr Mesh	Moore Street	643 m	Less than 50%	53%	127	Monitor growth
PAL CB8/10/12	3 Fdr Mesh	Palm Grove	1,105 m	65%	81%	5,410	Monitor Growth
UNI CB12	Radial	University	5 m	61%	69%	1,388	Monitor growth

Table 8-15 Distribution Level Issues

Cascade tripping of ring feeders for a loss of a single feeder section is a possibility due to the overcurrent settings applied at the zone substation. Settings are typically set for protection of the feeder breaker and an allowable short time overload of the cables. The sudden loss of a single feeder may result in the transfer of load to the remaining feeders and may cause a trip of the feeder protection relays at the zone substation. Each subsequent trip may result in further overload of the remaining feeders. The result is the possible loss of the entire mesh ring and possible equipment damage due to overloading prior to the protection devices clearing.

Table 8-16 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
EVA 2/3	EVA CB02 Out	EVA CB03	988 m	102%	Network augmentation
	EVA CB03 Out	EVA CB02	1,533 m	130%	
FRE 3/4/5/6	FRE CB03 Out	FRE CB08	328 m	108%	Optimise open points and monitor growth
FRE 13/14	FRE CB13 Out	FRE CB14	593 m	105%	Network augmentation
	FRE CB13 Out	FRE CB13	778 m	120%	
KAR 3/6	KAR CB03 Out	KAR CB06	1,923 m	138%	Network augmentation
	KAR CB06 Out	KAR CB03	1,095 m	122%	
PAL 8/10/12	PAL CB12 Out	PAL CB8/10	2,035 m	116%	Network augmentation
UNI 8/10	UNI CB08 Out	UNI CB10	1,931 m	104%	Optimise open points and monitor growth
	UNI CB10 Out	UNI CB8	588 m	103%	
Within 5 years					
IRA 8/9	IRA CB08 Out	IRA CB09	385 m	111%	Optimise open points and monitor growth

Table 8-16 Meshed Ring Feeder Contingency Analysis

8.4.3 Southern Area Sub transmission and Distribution Development Options

This section summarises the options available to meet the development needs described above.

As the distribution network within the Southern Area is highly meshed, the development options for the Wellington CBD are comprised of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive because there are options that meet several needs for the same investment.

8.4.3.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions to defer investment. These options include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over construction of redundant capacity; and
- Consideration of the cost effectiveness of demand side management to alleviate localised network constraints.

These non-network solutions will be implemented prior to any network investment. WELL currently monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets. Where thermal overload limits are at risk of being exceeded 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.

8.4.3.2 Network Investment Options

Common Development Projects

A number of projects within the Wellington CBD will be required to augment the network and improve security of supply. These projects are required irrespective of the development option selected and are as follows:

- A new feeder from Moore Street to reinforce the Moore Street 12/14 ring feeder, interconnecting with feeders from Kaiwharawhara and supplying Westpac Stadium and Centerport. This is dependent on the recovery strategy of the port following the November 2016 Kaikoura earthquake and customer funding being made available;
- Balancing bus section load at a number of zone substations, which will involve physically swapping feeders between the two bus sections;
- The installation of a new 33 kV special protection scheme or a 33kV bus at Evans Bay which will defer replacement of the Evans Bay cables which have a low asset health condition. Although this investment has a condition based driver, it has been included in the network development section because of its impact on the configuration of the 33 kV sub transmission network; and

- Installation of bus-tie changeover schemes at all zone substations in the Southern Area to allow rapid restoration of supply following sub transmission faults.

Southern Area Development Options

Two network development options have been identified and evaluated against the development needs described in Sections 8.4.2.1 and 8.4.2.2.

The two options assessed for the planning period are:

- Option 1: Installation of a new zone substation supplied from Central Park GXP with distribution level interconnections to The Terrace, Frederick Street and Palm Grove; and

- Option 2: Augmentation of the existing sub transmission and distribution infrastructure to alleviate constraints and improve transfer capacity.

Two studies were commissioned to determine costing and feasibility to a higher degree of confidence so an informed decision can be made as to the recommended development path. These studies were:

- Feasibility and cost estimation of establishing a new zone substation within the CBD;

- Review and cost estimation of the Network Development and Reinforcement Plan, and all component projects for the two options listed above.

Each of the options is described in more detail below.

Option 1: Installation of a New Zone Substation

This option involves installation of a new zone substation, supplied from Central Park GXP. The new zone substation would have distribution feeders inter-connecting with The Terrace, Frederick Street, Kaiwharawhara and Palm Grove. The proposed distribution connectivity is to ensure this option will mitigate the identified issues with an integrated solution.

Load would be permanently transferred from the highly loaded feeders from The Terrace, Palm Grove and Frederick Street to the new zone substation. This would have the effect of alleviating loading constraints at the distribution and sub transmission level at both of these sites.

Figure 8-26 illustrates the final configuration of Option 1.

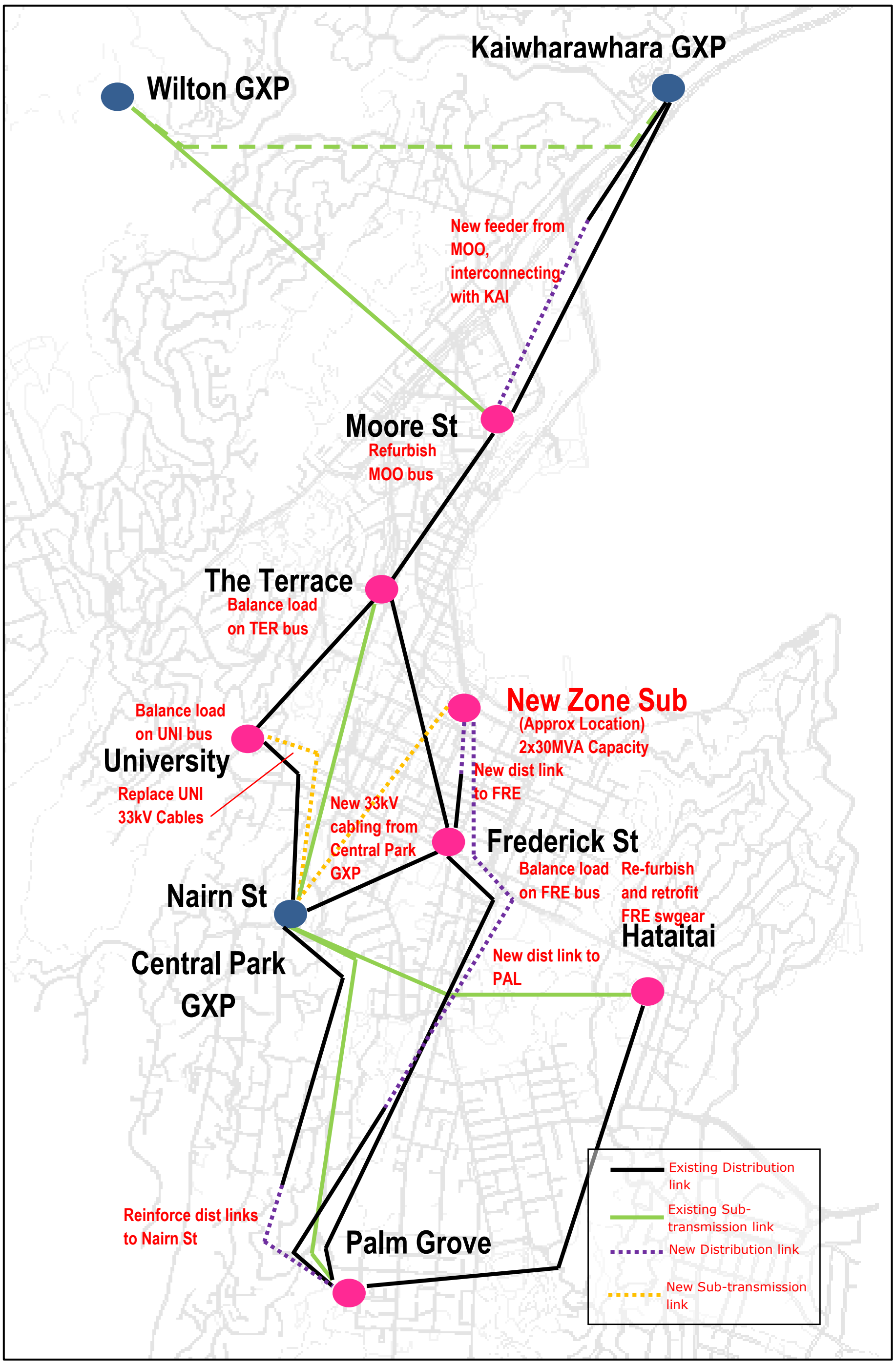


Figure 8-26 Proposed Configuration for Option 1

The implementation of the option would be staged to align with the timing of constraints as they arise.

A pre-feasibility study into establishing a new zone substation in the CBD has provided a ±30% cost estimate for the zone substation component of this option. The separate external review of the NDRP has provided more detailed costing of all sub transmission and distribution works required in addition to the establishment of the new zone substation. The cost of this network development option is shown in Table 8-17.

Project Description	Cost ($M)
Construction of a zone substation within the CBD (±30%) and network reinforcement	22.4
Planned common projects for both options	13.0
Total Southern Area NDRP Investment - Option 1	**35.4**
Condition-based Asset Renewal Expenditure	9.0

Table 8-17 Estimated Cost of Network Development Option 1

*Note: The asset renewal expenditure under Option 1, used in the NPV analysis is $9 million. This is lower than accounted for in Option 2 ($12.5 million), as it reduces the criticality of a number of switchboards in the CBD, allowing capital expenditure deferral.

Option 2: Sub transmission & Distribution Level Augmentation

Option 2 involves augmentation of the sub transmission and distribution networks to alleviate the identified issues. It provides for distribution reinforcement projects to improve capacity and security of supply. Sub transmission issues are mitigated through load transfer to adjacent zone substations or by upgrading asset capacity.

This option includes:

- Replacing the sub transmission cables to Frederick Street with new high capacity XLPE cables. These cables will offer sufficient capacity to cater for the expected growth at Frederick Street while also providing additional capacity for contingency operation.

- Alleviating the issues at Palm Grove in isolation from the rest of the network. Further sub transmission capacity is provided by replacing the Palm Grove transformers with two new 36MVA units. The Palm Grove 8/10/12 feeder ring has 5,000+ ICPs is to be reconfigured and reinforced to alleviate loading on this distribution ring and improve security of supply to the Newtown area. The existing inter-connections between Palm Grove and Nairn Street are reinforced to provide post-contingency transfer capacity for a sub transmission fault at Palm Grove.

Figure 8-27 provides a visual representation of the end product of this development path.

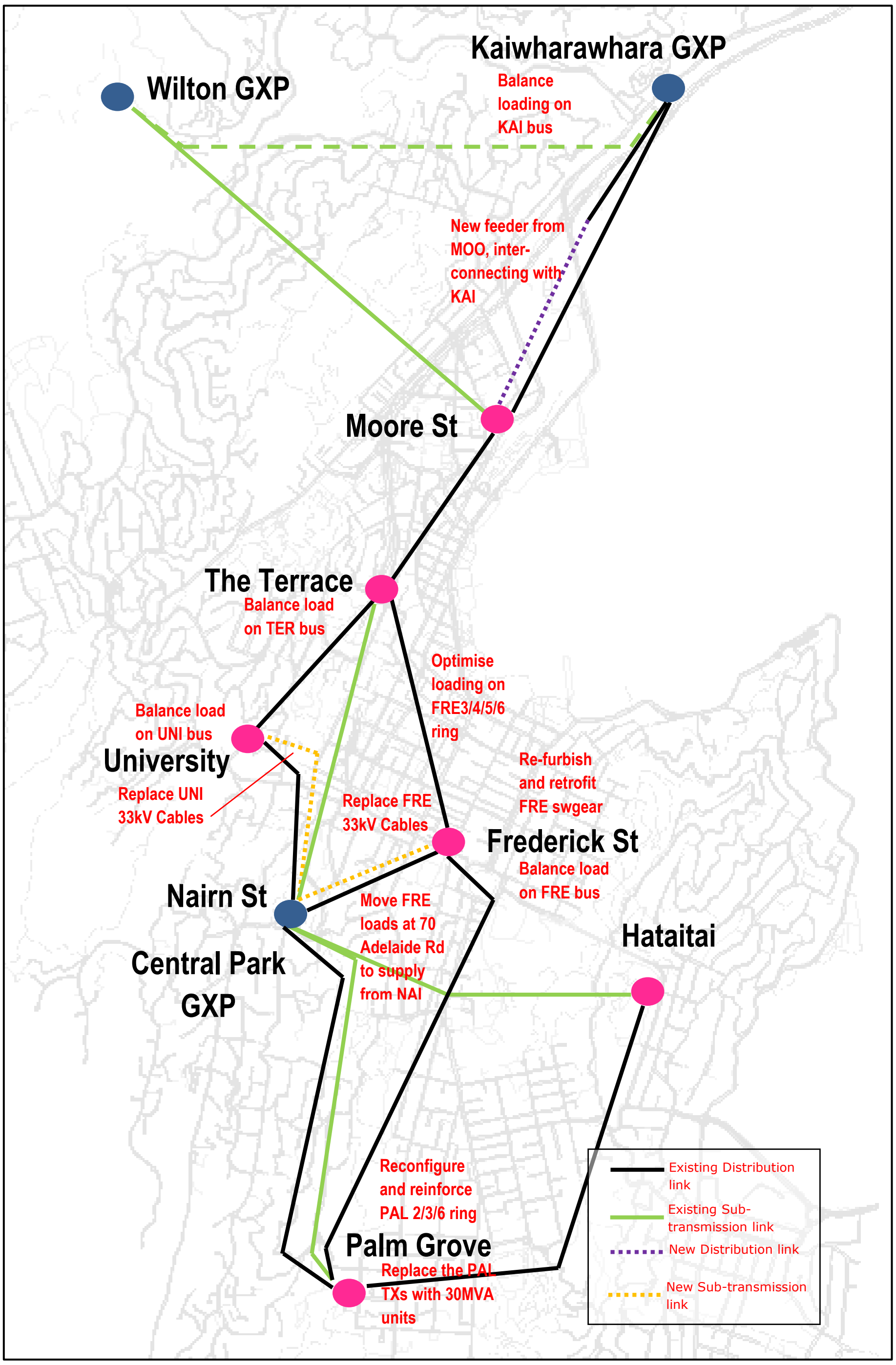


Figure 8-27 Proposed Configuration for Option 2

The estimated cost of implementation of this network development option is shown in Table 8-18.

Project Description	Cost ($M)
Total marginal cost of network reinforcement for capacity	6.5
Planned common projects for both options	13.0
Total Southern Area NDRP Investment - Option 2	**19.5**
Condition-based Asset Renewal Expenditure	2.1

Table 8-18 Estimated Cost of Network Development Option 2

8.4.4 The Southern Area Development Plan

Option 2 is the most cost effective option which mitigates all identified issues while also ensuring a balanced network

It has the benefit of introducing high capacity ties between critical zone substations as well as increasing capacity and replacing aging sub transmission assets. It involves the following major milestones and timing of works to mitigate the identified constraints in the most cost effective manner:

- **2019** – Open point shifts to temporarily alleviate distribution level constraints and defer network investment till 2019;
- **2020 – 2021** – Replacement of the Frederick Street gas filled sub transmission cables with new high capacity XLPE cables to improve capacity at Frederick Street;
- **2022 – 2024** – Reinforcement of the Palm Grove 8/10/12 feeder ring; and
- **2025** – Reinforce HV ties between Palm Grove, Nairn St, Hataitai and Evans Bay for supply reliability and capacity improvements.

The majority of identified feeder loading risks will be eliminated by the end of the planning period. A number of feeder overloads at Moore Street, Palm Grove and Nairn Street are accepted on the basis of the ability to enact contingency load shifts to an adjacent zone following retrofit of remote switching and telemetry to a number of network critical distribution switching points throughout the network. Frederick and Karori feeder augmentations will be resolved by the allowances included in the summary provided in section 8.4.5.

Condition based asset replacement/refurbishment projects identified in this development plan were discussed further in Section 7.

8.4.5 Summary of the Southern Area Investment

Table 8-19 shows the investment plan projects in the Wellington Southern area for the planning period from 2018-2028.

Year	Project	Estimated Cost ($K)	Comments
2019	Evans Bay 33 kV Protection Scheme – Year 1	500	Common Project
	Bus-tie changeover implementation - Year 1	300	Common Project
	Frederick Street Sub transmission Cable Replacement and Protection Upgrade – Year 1	2,800	NDP Option 2
	Allowance for minor cable reinforcement works	400	Common Project
Year Total		**4,000**	
2020	Evans Bay 33 kV Protection Scheme – Year 2	700	Common Project
	Frederick Street Sub transmission Cable Replacement and Protection Upgrade – Year 2	2,800	NDP Option 2

Year	Project	Estimated Cost ($K)	Comments
	Moore Street - New Feeder	160	Common Project
	Bus-tie changeover implementation - Year 2	400	Common Project
	Allowance for minor cable reinforcement works	300	Common Project
Year Total		**4,360**	
2021	Balance loading on Kaiwharawhara bus	100	NDP Option 2
	Moore Street - New Feeder	1,000	
	Frederick Street Sub transmission Cable Replacement and Protection Upgrade – Year 3	1,700	NDP Option 2
	Bus-tie changeover implementation – Year 3	300	Common Project
	Allowance for minor cable reinforcement works	200	Common Project
Year Total		**3,300**	
2022	Palm Grove Ring Reinforcement - Stage 1	1,500	NDP Option 2
	Allowance for minor cable reinforcement works	400	Common Project
Year Total		**1,900**	
2023	Balance loading on Frederick Street bus	100	NDP Option 2
	Palm Grove Ring Reinforcement - Stage 2	1,000	NDP Option 2
	Allowance for minor cable reinforcement works	400	Common Project
Year Total		**1,500**	
2024	Allowance for minor cable reinforcement works	400	Common Project
Year Total		**400**	
2025	Allowance for minor cable reinforcement works	**500**	Common Project
2026	Palm Grove HV Ties - Year 1	1,300	NDP Option 2
	Allowance for minor cable reinforcement works	800	Common Project
Year Total		**2,100**	
2027	Palm Grove HV Ties - Year 2	1,700	NDP Option 2

Year	Project	Estimated Cost ($K)	Comments
	Allowance for minor cable reinforcement works	500	Common Project
Year Total		**2,200**	
2028	Allowance for minor cable reinforcement works	**500**	Common Project
	Total Investment	**20,760**	

Table 8-19 Summary of Southern Area Investment Requirement ($K in constant prices)

8.5 Northwestern Area NDRP

Figure 8-28 Porirua City looking North[57]

This section provides a summary of the Northwestern Area NDRP. This section is structured as follows:

- Identified GXP development needs;
- Identified sub transmission and distribution level development needs and options;
- The network development plan for the planning period; and
- A summary of the expected expenditure profile.

Detail of each project in the development plan is described in Appendix C.

[57] Photography credit: Porirua City Council

8.5.1 GXP Development

The Northwestern Area is supplied from two GXPs, Pauatahanui and Takapu Road. The transformer capacity and the sustained maximum demand are set out in Table 8-20.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Maximum Demand (MVA)	
			2018	2028
Takapu Rd 33 kV	2x90	111 / 116	88	100
Pauatahanui 33 kV	2x20	22 / 24	18	18
Total (after diversity)	-	-	**106**	**117**

Table 8-20 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.

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 2018 was 88 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 sub transmission circuits supplied from Takapu Road.

The Ngauranga sub transmission circuits from Takapu Rd GXP are 110 kV lines, operating at 33 kV, installed on steel pylon towers and owned and maintained by Transpower. A number of factors need to be considered in determining the long term viability of this arrangement such as:

- Maintaining the status quo;
- Transpower's preference to decommission the overhead lines in the future. This will require additional investment to enable the reconfiguration of the existing supply arrangement;
- WELL taking ownership of the 110 kV lines, or part of the line to supply a new zone substation for the Western area;
- The possibility of undergrounding the lines from Takapu Road.

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 sustained peak demand on the Pauatahanui GXP in 2018 was 18 MVA. 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 replacement will be required within the next 5-10 years. Potential housing and small industrial development in Plimmerton (northern growth area) will add up to 6 MVA to the peak demand, 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 in 2019 with local council and developers. WELL will discuss with Transpower the potential options for alleviating or replacing the Pauatahanui supply transformers.

WELL will also consider an upgrade of the sub transmission differential protection from this site within the planning period.

8.5.2 Sub transmission and Distribution Development Plan

This section describes the identified security of supply constraints and development needs for the Northwestern Area sub transmission and distribution networks.

The Northwestern network consists of 12 sub transmission 33 kV circuits supplying seven 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 8-21.

Zone Substation	Transformer Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Sustained Peak Demand (MVA)		Date constraints are binding and season constrained	ICP counts as at 2018
		Winter	Summer		2018	2028		
Existing constraints								
Johnsonville	18.4	21	14	Winter	21	24	Existing Winter and Summer constraint	8,419
Mana	16 / 7 (transformer / bus-tie)	33	23	Winter	9	9	Existing Winter constraint	4,702
Plimmerton	16/ 7 (transformer / bus-tie)	33	23	Winter	9	9	Existing Winter constraint	2,487
Porirua	16	22	14	Winter	20	25	Existing Winter and 2019 Summer constraint	3,787
Forecasted constraints								
Kenepuru	18.4	19	14	Winter	11	16	2021 Summer constraint	2,231
Not Constrained								

Zone Substation	Transformer Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Sustained Peak Demand (MVA)		Date constraints are binding and season constrained	ICP counts as at 2018
		Winter	Summer		2018	2028		
Ngauranga	12	20	14	Winter	10	10	Not Constrained	4,482
Tawa	15	25	17	Winter	14	15	Not Constrained	5,467
Waitangirua	15	25	19	Winter	13	13	Not Constrained	5,999

Table 8-21 Northwestern Area Zone Substation Capacities

The development needs for the Northwestern Area at the sub transmission and distribution level are outlined in the following sections.

8.5.2.1 Sub transmission Development Needs

Sub transmission 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.

Mana & Plimmerton

The Mana and Plimmerton zone substations are each supplied via a single sub-transmission circuit (i.e., a single 33/11 kV transformer and 33 kV circuit from Pauatahanui GXP). The 11 kV buses of the two zone substations are connected via an 11 kV bus tie cable.

Should the 33 kV circuit supplying either zone substation be out of service, the peak load cannot be supplied through the existing 11 kV tie cable and load transfer to other zone substations is required, as summarised in Table 8-22.

Circuit	Season	Mana-Plimmerton Bus-tie capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
Mana	Winter	7	9.3	2.3
	Summer	7	6.6	0
Plimmerton	Winter	7	8.7	1.7
	Summer	7	6.0	0

Table 8-22 Mana and Plimmerton Load at Risk

The single transformer at either site cannot supply the combined peak load for the two sites. Table 8-23 shows the combined peak load and the current load at risk at Mana/Plimmerton.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
Mana-Plimmerton	Winter	16	18.4	2.4
	Summer	16	11.3	0

Table 8-23 Mana-Plimmerton Combined Load at Risk

Figure 8-29 shows the load duration curve against the N-1 cyclic rating of the 11 kV bus-tie.

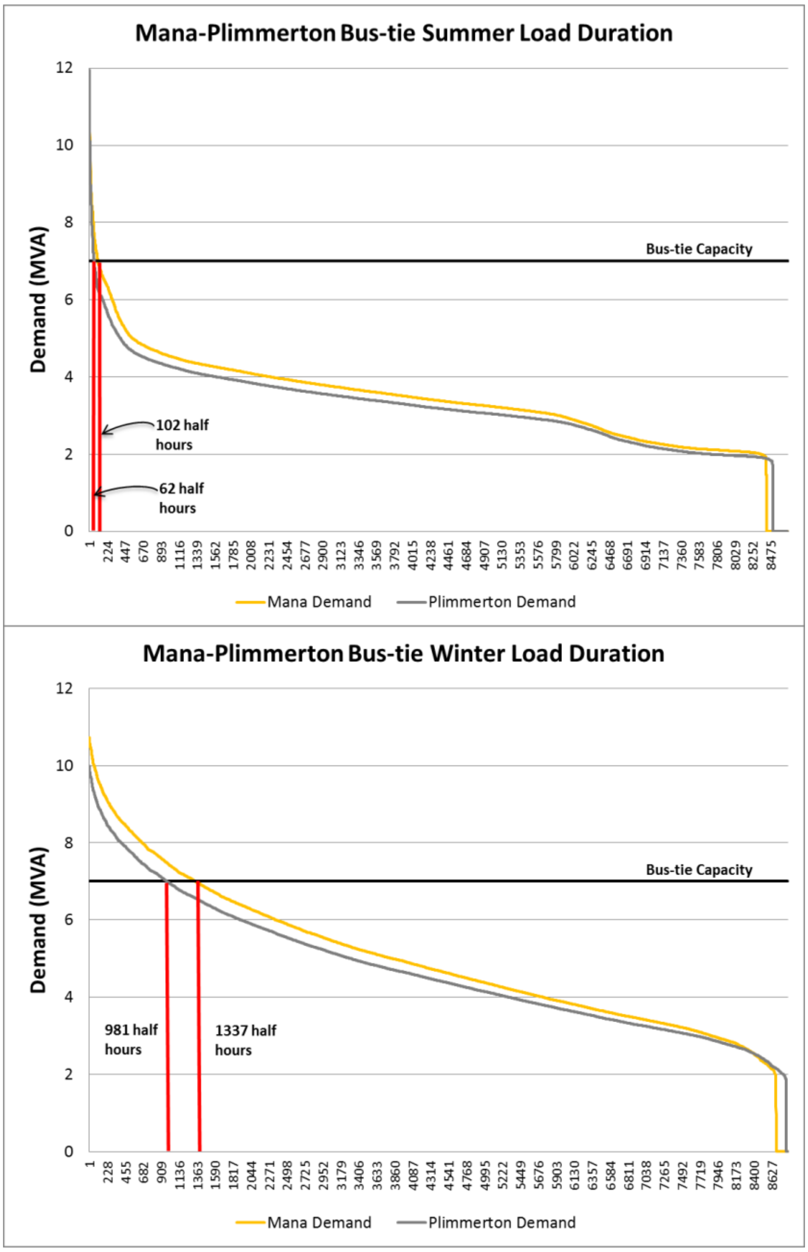


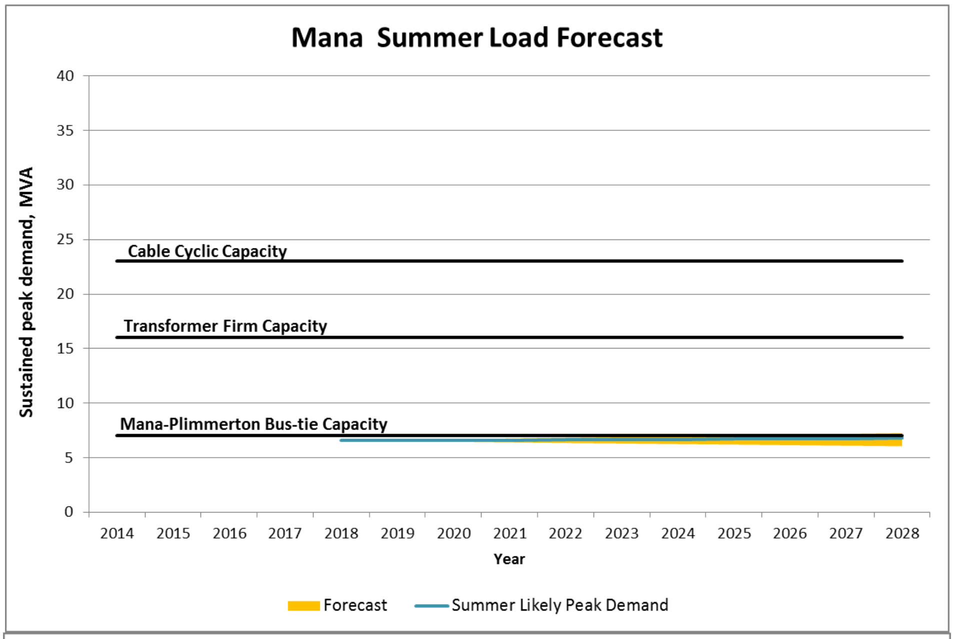
Figure 8-29 Mana-Plimmerton Bus-tie Load Duration

The load duration plot shows that the worst case is an outage of the Mana sub transmission circuit where the peak demand at Mana would exceed the available capacity of the bus-tie for approximately 14% of the time in a year. This load duration curve is based on 30 minute periods and is higher than the sustained peak.

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.

Figure 8-30 shows the forecast demand for Mana zone substation based on the estimated growth scenarios and development within the planning period. The sub transmission capacity constraints are plotted for comparison. Figure 8-31 shows the equivalent graphs for Plimmerton zone substation.



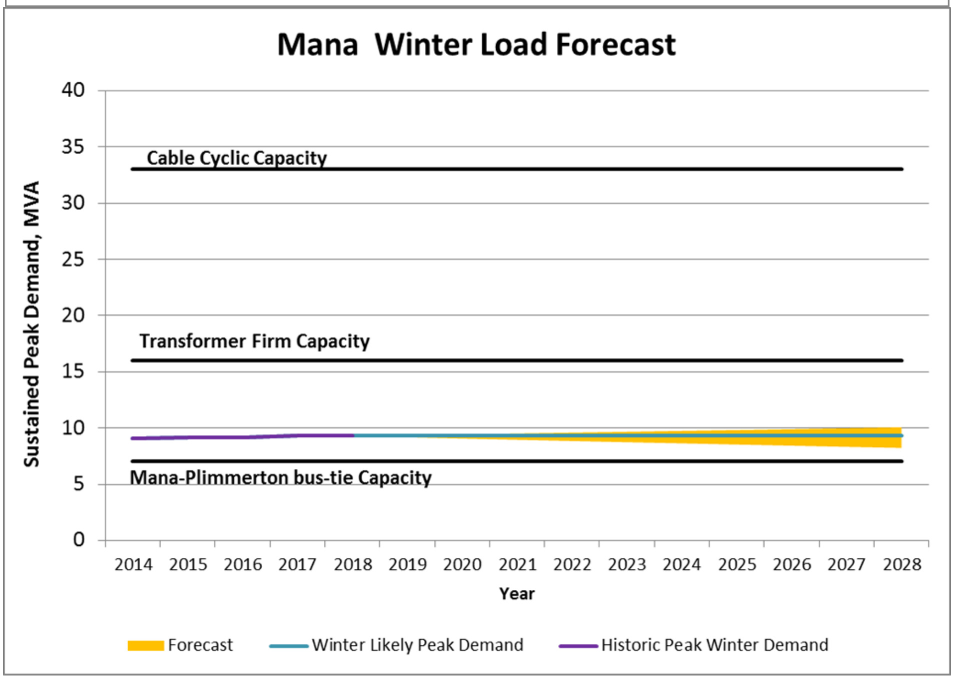
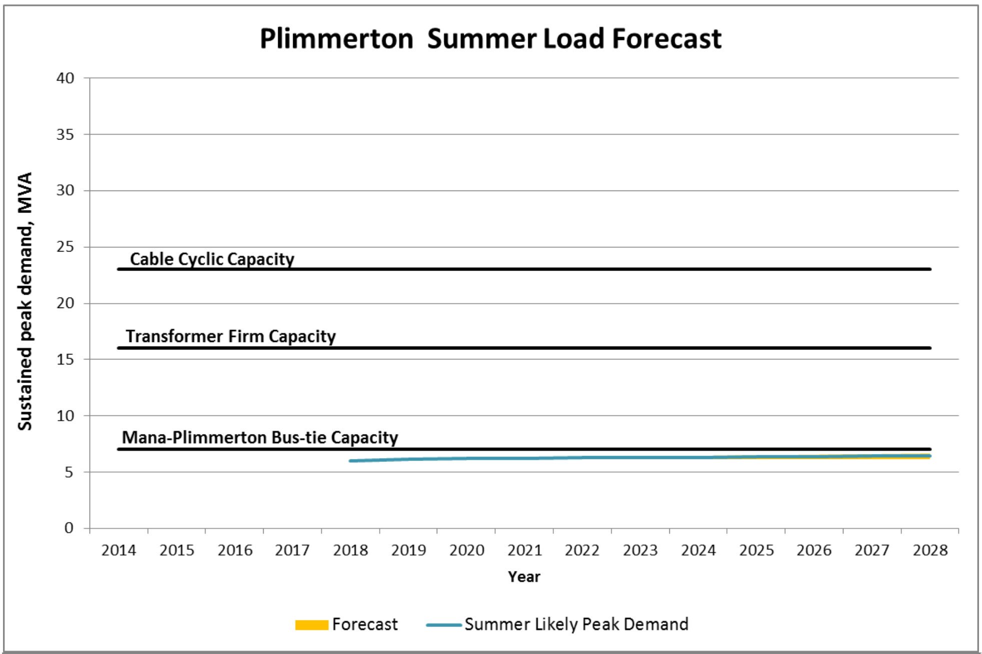


Figure 8-30 Mana Load Forecast



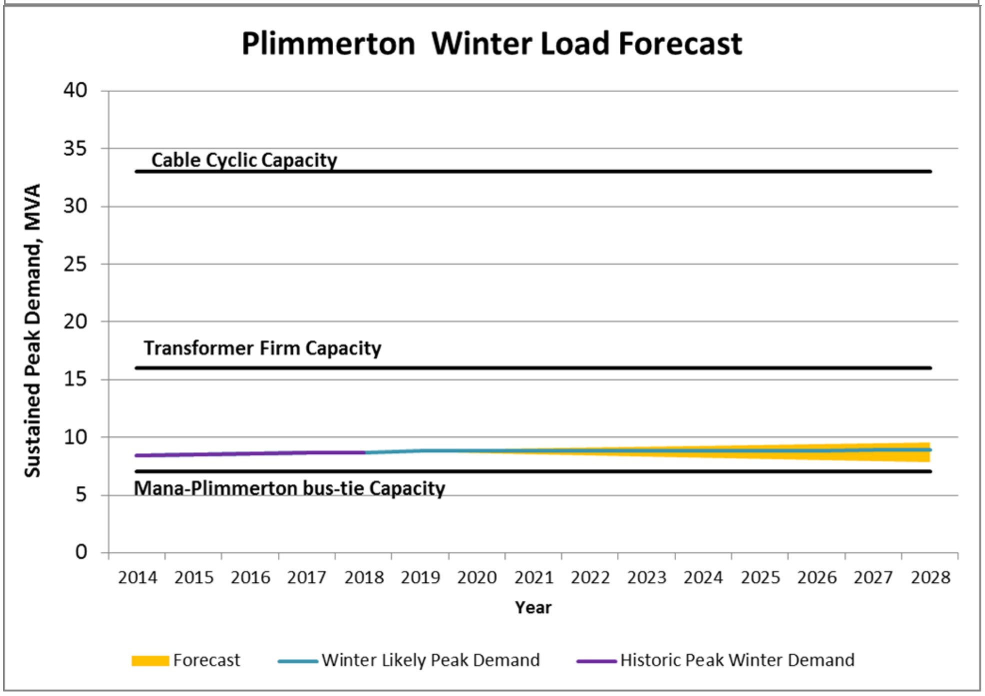


Figure 8-31 Plimmerton Load Forecast

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 development is not included in this forecast due to its uncertainties). 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.

Porirua

The peak load supplied at Porirua exceeds the n-1 transformer ratings during the winter period, and the 33kV circuit rating during summer. The risk of having further constraints is dependent on planned step change demands due to re-development of the Porirua city centre and a number of residential subdivisions in the Whitby and Aotea areas.

Following a fault on the sub transmission system, load will need to be off-loaded from Porirua to an alternative zone substation.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
Porirua A	Winter	16	20.9	5.9
	Summer	14	15.8	1.8
Porirua B	Winter	16	20.9	5.9
	Summer	14	15.8	1.8

Table 8-24 Porirua Sub transmission Capacity Shortfall

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 8-32 shows the load duration curve against the N-1 cyclic ratings of transformer and sub transmission cable.

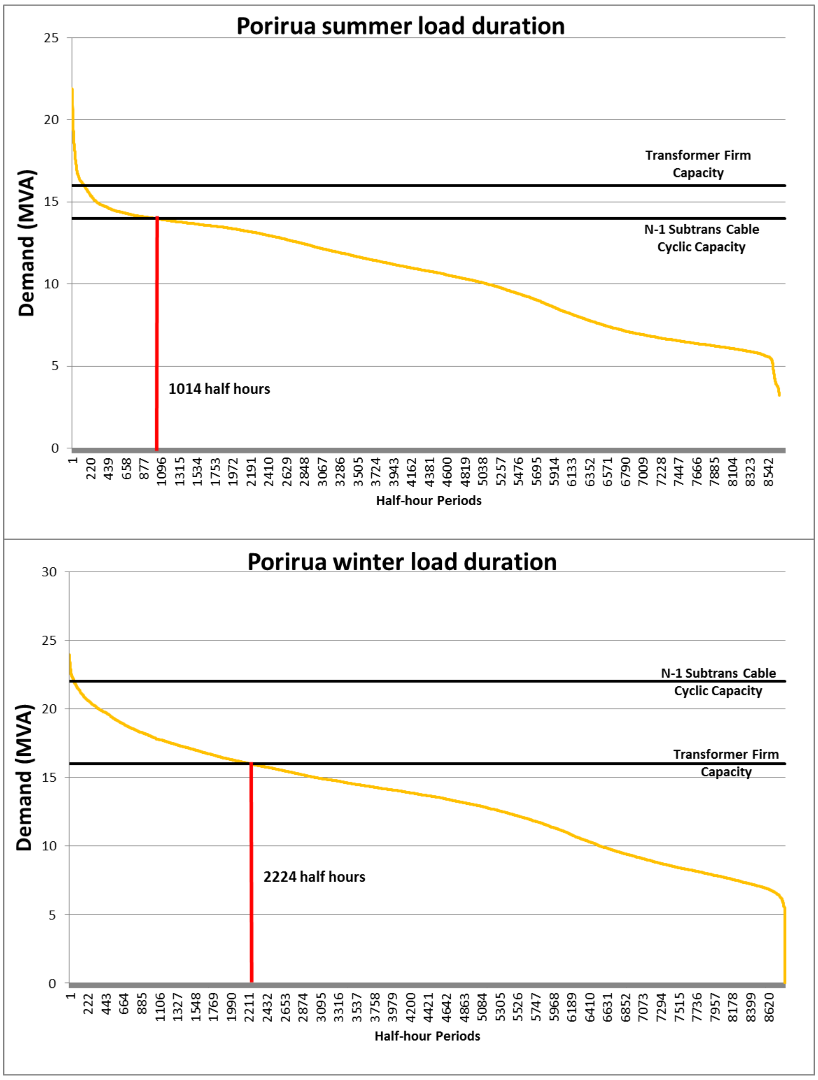


Figure 8-32 Porirua Load Duration

The load duration curve shows that at present, demand exceeds N-1 sub transmission capacity for approximately 25.4% of the time during winter and 11.6% during summer. A step change demand of 1.2MVA is expected within the next two years which may increase the peak load duration further. 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 8-33.

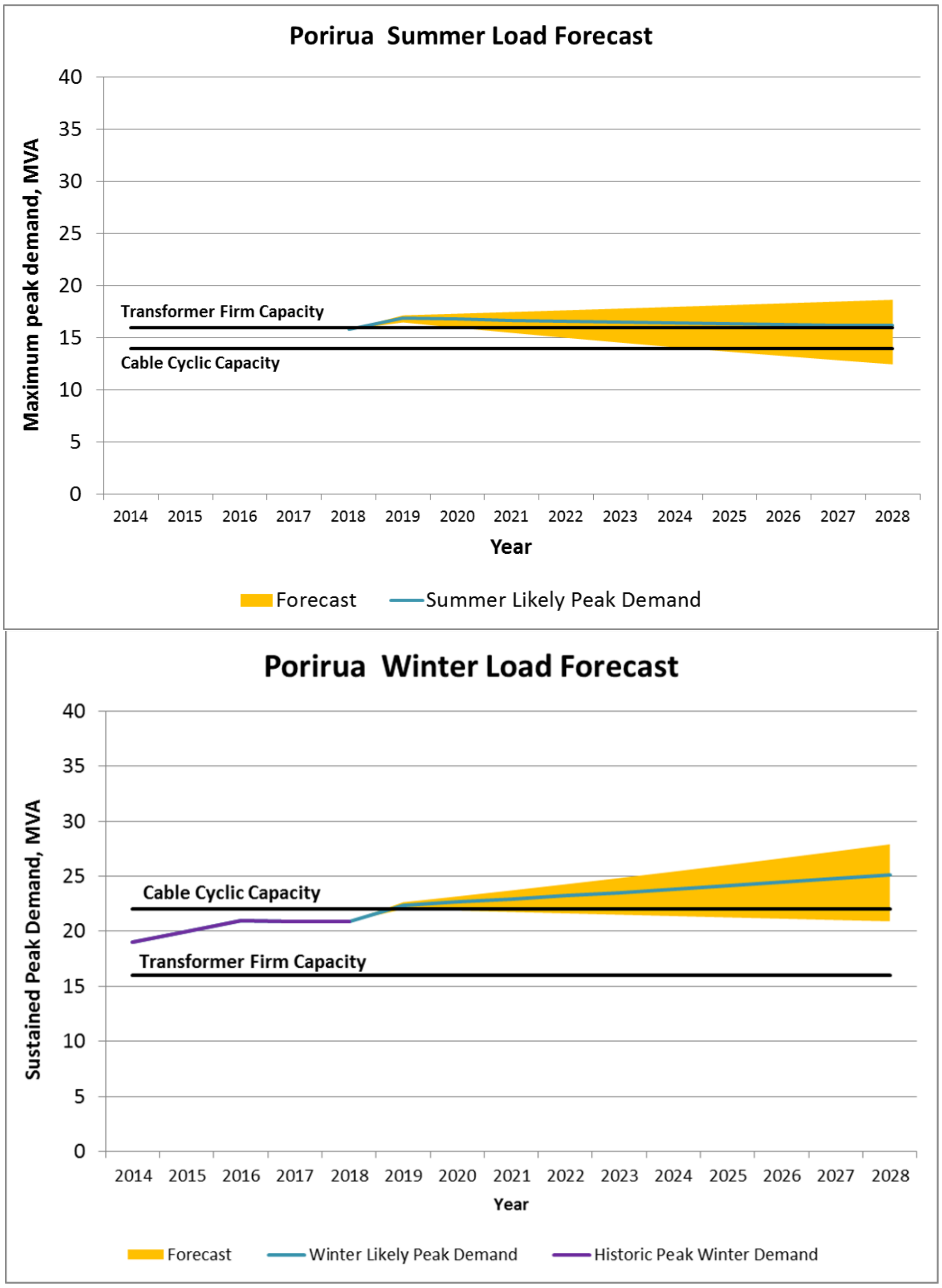


Figure 8-33 Porirua Load Forecast

The shortfall in N-1 capacity could increase to 4-9 MVA by the end of the planning period.

Johnsonville

The sustained peak load supplied by Johnsonville is currently exceeds the cyclic N-1 capacity of the sub transmission circuits. Operational risk is currently managed by load control and transfer via open points to HV feeders from other zone substations.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
Johnsonville A	Winter	18.4	20.8	2.4
	Summer	14	11.2	0
Johnsonville B	Winter	18.4	20.8	2.4
	Summer	14	11.2	0

Table 8-25 Johnsonville Sub tranmission Capacity Shortfall

Figure 8-34 shows the load duration curve against the N-1 cyclic ratings of transformer and sub transmission cables for Johnsonville. The load duration curves shows that at present the demand exceeds the firm capacity about 6.4% of the year. This exceeds the network security standard for a mixed commercial and residential zone substation.

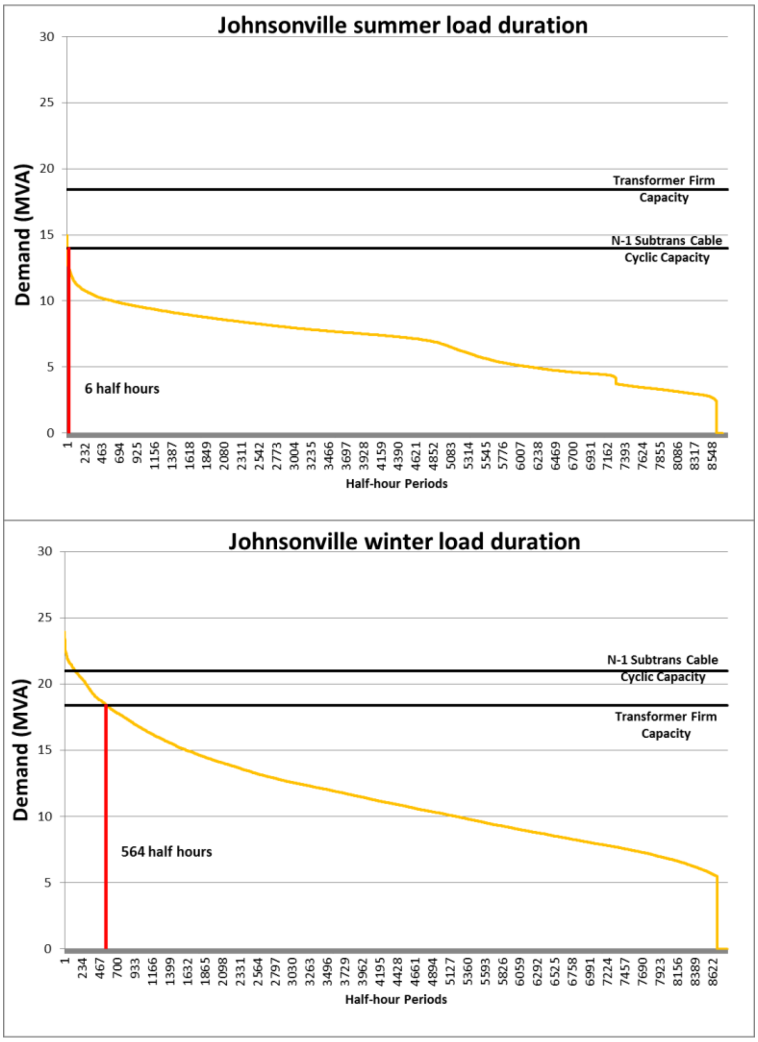
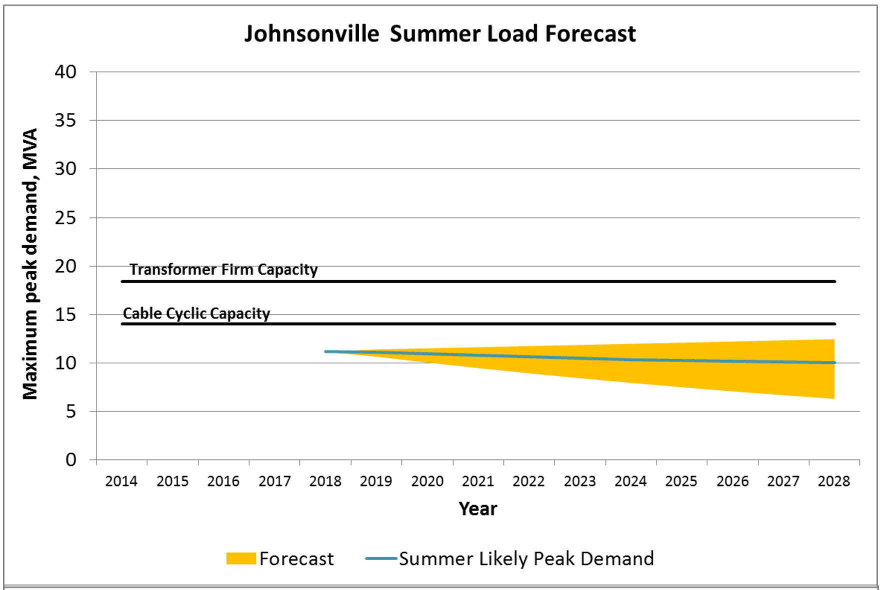


Figure 8-34 Johnsonville Load Duration

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Johnsonville is forecasted to grow as show in Figure 8-35.



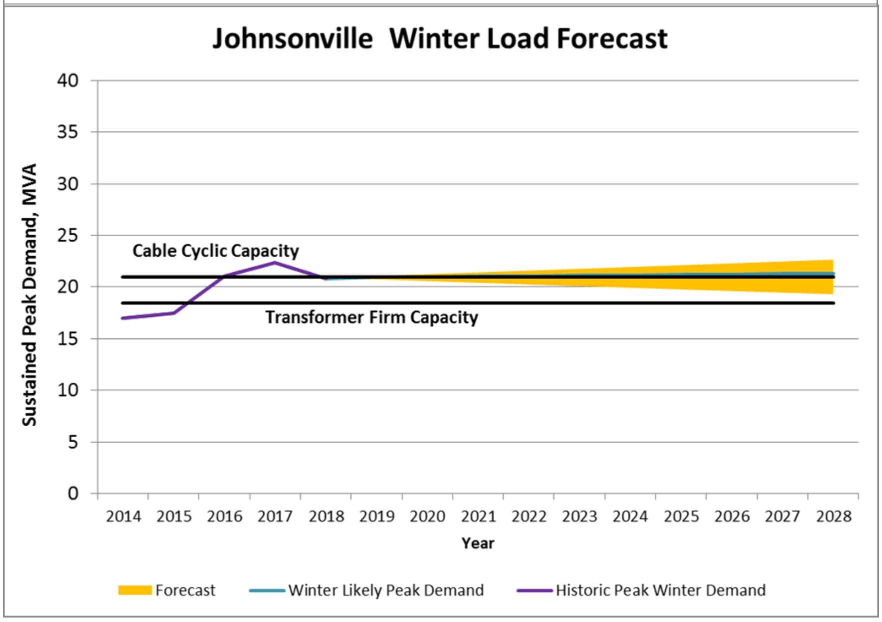


Figure 8-35 Johnsonville Load Forecast

Kenepuru

At present, maximum demand at Kenepuru is within available N-1 sub transmission capacity. It is forecasted that with growth, the sustained peak demand could exceed the N-1 cyclic capacity by 2021.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2021 (MVA)	Minimum off load for N-1 @ peak (MVA)
Kenepuru A	Winter	18.4	14.9	0
	Summer	14	14.1	0.1
Kenepuru B	Winter	18.4	14.9	0
	Summer	14	14.1	0.1

Table 8-26 Kenepuru Sub transmission Capacity Shortfall

According to the load forecast, the peak load will be marginally above the equipment rating and does not require network argumentation.

Forecasted load growth could come from a proposed new residential sub-division, a retirement village and hospital expansion. WELL will continue monitoring load growth and manage the overloading risk through operational control. Figure 8-36 shows the forecast demand for Kenepuru zone substation.

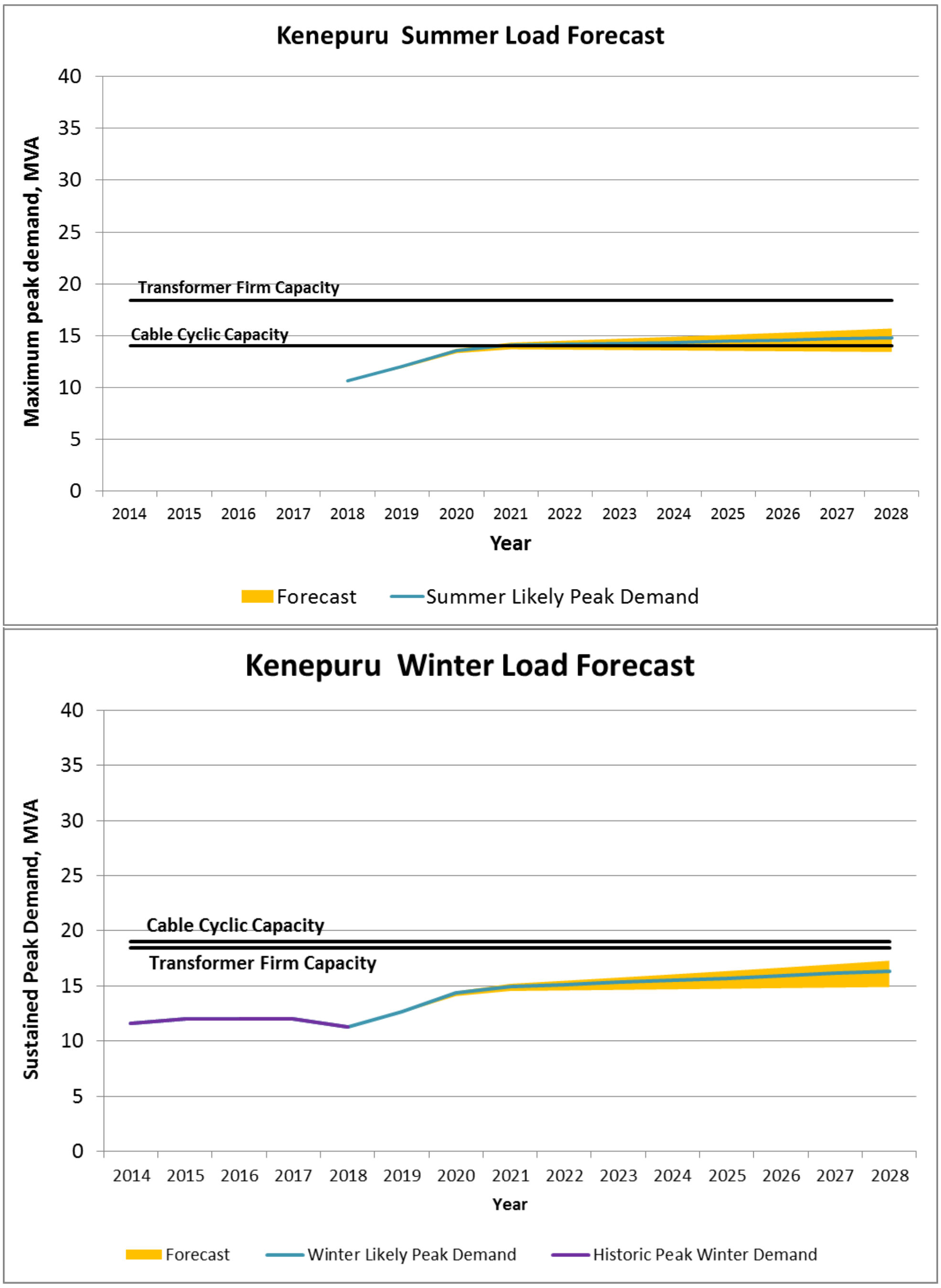


Figure 8-36 Kenepuru Load Forecast

8.5.2.2 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 8-27 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	Control
Current							
JOH CB6	Radial	Johnsonville	785 m	79%	80%	1,792	Network augmentation
POR CB4/5	2 Fdr Mesh	Porirua	591 m	74%	74%	378	Network augmentation
POR CB06	Radial	Porirua	591 m	79%	79%	42	Network augmentation
POR CB1/11	2 Fdr Mesh	Porirua	8,590 m	65%	65%	3,224	Network augmentation
TAW CB11	Radial	Tawa	1,732 m	68%	76%	544	Monitor growth
WTA CB5	Radial	Waitangirua	2,816 m	74%	65 %	1,692	Network augmentation

Table 8-27 Distribution Level Issues

Table 8-28 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 2018.

Meshed Ring	Topology	N-1 Case	Feeder	Length of overloading section	Contingency Loading	Control
POR 1/11	2 Fdr Mesh	POR 01 out	POR 11	4,291 m	134%	Network augmentation
		POR 11 out	POR 01	4,291 m	134%	
POR 4/5	2 Fdr Mesh	POR 04 out	POR 05	591 m	127%	Network augmentation
		POR 05 out	POR 04	1,707 m	102%	

Table 8-28 Meshed Ring Feeder Contingency Analysis

8.5.3 Northwestern Sub transmission and Distribution Development Options

This section describes the development options available to mitigate the constraints described above.

The development options for the Northwestern Area are comprised of a combination of the individual solutions required to meet each need. Each individual solution is not mutually exclusive because there are solutions which meet several needs for the same investment.

The purpose of this section is to describe those development options, establish the overall economic cost of each and identify the optimal staging of investments over the period. As it is impractical to cover all possible combinations of solutions, this section covers four primary development options. Each option has been refined before being presented here to ensure that it is practical. Each result in a different supply risk profile based on the solutions utilised.

8.5.3.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to implement non-network solutions to defer significant short term investment. These options include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over construction of redundant capacity; and
- Consideration of the cost effectiveness of demand side management to alleviate localised network constraints.

These non-network solutions will be implemented prior to any network investment. WELL currently monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets. Where thermal overload limits are at risk of being exceeded, network controllers are able to:

- Initiate shedding of hot water load to provide peak shaving during peak demand periods (in the Northwestern Area, ripple injection is at the zone substation level); and
- Fine tune network open points to optimise feeder loading and feeder customer numbers.

8.5.3.2 Network Investment Options

Common Development Projects

A number of projects will be required to replace assets and improve security of supply. These projects are required irrespective of the development option selected and are as follows:

- Installation of communication and protection links between all zone substations in the Porirua basin to provide protection and SCADA communications while also accommodating future IP connectivity requirements;
- Switching to balance sub transmission loading between Mana and Plimmerton. These works are implemented in lieu of a SPS scheme to limit the load at Mana/Plimmerton to within the capacity of the bus-tie to provide for N-1 security;

- A number of isolated distribution level projects are required in areas to reduce the risk of supply outages to areas with high customer counts or high priority customers; and

- Installation of sectionaliser scheme for Tawa/Kenepuru sub transmission circuits.

Northwestern Area Development Options

The development needs in the Northwestern Area can be separated into two independent areas:

1. North of Tawa, the Porirua Basin and up to Plimmerton. This area is supplied from Porirua, Waitangirua, Mana and Plimmerton zone substations (area referred to as the North below); and

2. The Northwestern suburbs between Ngauranga and Tawa. This area is supplied from Ngauranga, Johnsonville, Tawa and Kenepuru zone substations (area referred to as the South below).

For each area, studies have identified that there are two distinct methods for mitigating the issues in each:

   a. Augmentation of existing network infrastructure through network upgrades; or

   b. Installation of a new zone substation.

Together with the combination of these aspects, four development options for the Northwestern Area are considered. The four options are:

1. Augmentation in both the North (1a) and the South (2a): Replacement of sub transmission assets where required, distribution level augmentation to relieve highly loaded feeders;

2. Installation of a new zone substation in the North (1b) and augmentation in the South (2a): Install a new zone substation in the Pauatahanui area; replace the Ngauranga transformers and shift open points in Johnsonville, Ngauranga and Tawa to relieve highly loaded feeders;

3. Augmentation in the North (1a) and install a new zone substation in the South (2b): Replace the Mana and Plimmerton transformers and install new distribution infrastructure to relieve highly loaded feeders and optimise loading between Porirua, Waitangirua, Mana and Plimmerton; install a new zone substation in the Grenada area; and

4. Installation of a new zone substation in the North (1b) and install a new zone substation in the South (2b): Install two new zone substations, one in the Grenada area and one in Pauatahanui. Optimise loading by shifting open points.

There are a number of benefits that each option offers, which need to be considered against the cost of each option. For example, the installation of a new zone substation at Pauatahanui provides the opportunity to mitigate the identified transmission constraints due to the capacity and age of the supply transformers by either:

- Upgrading the capacity of the Pauatahanui 110/33 kV transformers to provide capacity to the new Pauatahanui zone substation;

- Replacing the existing Pauatahanui 110/33 kV transformers with three-winding units and supplying a new Pauatahanui zone substation at 11 kV; or

- Installing two new 110/11 kV transformers at Pauatahanui to supply a new Pauatahanui zone substation.

Options involving a new zone substation in Grenada (Options 3 and 4) provide the opportunity to potentially decommission the Ngauranga zone substation. All supplied load from Ngauranga could be transferred to the new Grenada zone substation and Johnsonville, such that Ngauranga could be decommissioned.

The benefits and the costs of each option are described in more detail below.

Option 1: Augmentation in both the North (1a) and the South (2a)

This option involves augmentation of the sub transmission and distribution networks in both the north and south areas to alleviate the identified issues.

A number of open point changes are made to optimise loading in the network. The distribution augmentation projects are then implemented to overlay undersized cable segments and improve feeder capacity at Ngauranga, reinforce the distribution ring supplying the Porirua city centre and improve the inter-connectivity and capacity of the Waitangirua distribution network. A number of smaller projects are enacted around these works to alleviate localised distribution level constraints, replace aging assets and improve security of supply.

The demand at Pauatahanui GXP is constrained by the capacity of the 110/33 kV transformers. WELL would need to initiate a project with Transpower to replace these transformers with higher rated units as part of this option.

Figure 8-37 provides a visual representation describing the final network configuration from development path.

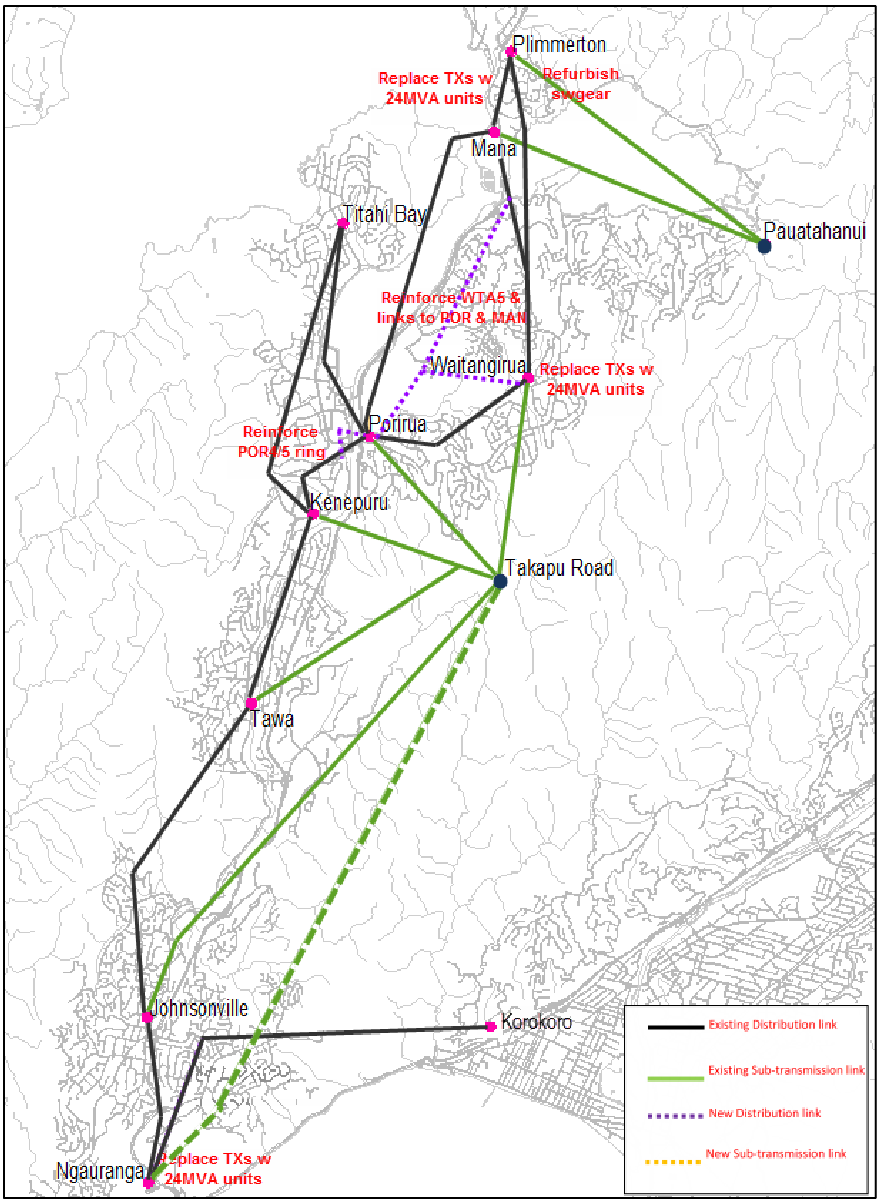


Figure 8-37 Network Configuration Option 1

The estimated cost of this network development option is shown in Table 8-29.

Project Description	Cost ($M)
Total marginal cost of network reinforcement	11.4
Common Projects for all options (communication & protection links + common cable reinforcements)	3.1
Total NW Area NDRP Investment - Option 1	**14.5**
Additional condition-based asset renewal projects required under Option 1	5.7

Table 8-29 Estimated Cost of Network Development Option 1

The benefits of this option are:

- Replaces assets nearing end of life, or posing a risk to network resilience;

- Increases capacity into high growth areas and zones with existing capacity constraints; and
- Projects can be separated into many discreet elements and scheduled to provide a more uniform investment profile.

The risks associated with this option are:

- Does not cater for long term growth outside of planning period or growth in excess of forecast; and
- Capacity based asset replacement at some sites where asset condition is generally good, but assets are highly utilised.

Option 2: Installation of a New Zone Substation in the North (1b) and Augmentation in the South (2a)

This option involves establishment of a new zone substation in the Pauatahanui/Whitby area, supplied from Pauatahanui GXP, to provide capacity for future growth in the North and relieve the loading at Waitangirua, Porirua, Mana and Plimmerton. The new zone substation would have distribution feeders inter-connecting with a number of highly loaded feeders within the Porirua basin.

There are three potential sub-options to provide sub transmission supply to this new zone substation:

1. Installation of new 33 kV cabling from Takapu Road. These cables would be terminated directly to two new 33/11 kV 24 MVA transformers. These transformers will feed the Pauatahanui zone substation bus. These works could be a customer initiated project with Transpower and funded through increased connection charges;
2. Installation of two new bays on the 110 kV bus at Pauatahanui GXP. The new 110 kV bays would supply two new 110/11 kV 24 MVA transformers, with an estimated cost of $3 million. These works would be a customer initiated project with Transpower and funded through increased connection charges; or
3. Replacement of the existing Pauatahanui 110/33 kV transformers with two new 110/33/11 kV transformers with capacity of at least 50 MVA. These transformers would supply both the 33 kV bus at Pauatahanui and the 11 kV bus at the new Pauatahanui zone substation. These works would be a customer initiated project with Transpower and funded through increased connection charges.

The recommended sub-option is to initiate a project with Transpower to replace the existing 110/33 kV transformers at Pauatahanui with two new 110/33/11 kV units.

A number of distribution level works will be enacted to overlay undersized cable segments and improve feeder capacity of Ngauranga, where feeders are connected to the Grenada area, as well as to reinforce the distribution ring supplying the Porirua city centre. Installation of a new zone substation in the Pauatahanui/Whitby area allows for reduction of utilisation at Mana and Plimmerton, potentially negating replacement of the transformers at these stations. Upgrade of the transformers at Ngauranga will be required.

Figure 8-38 provides a visual representation describing the final network configuration from the development path.

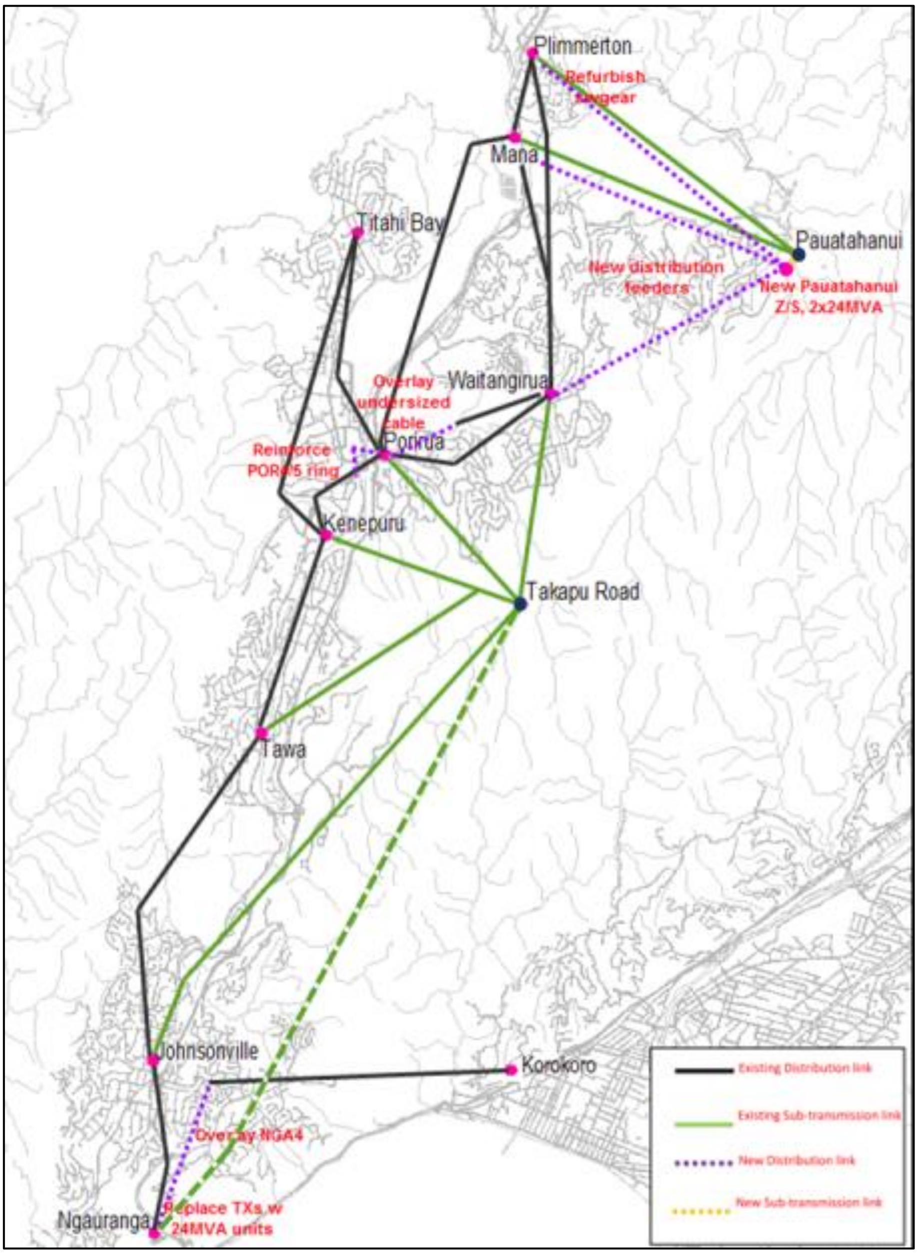


Figure 8-38 Network Configuration Option 2

The benefits of this option are:

- Introduces a new connection point from an independent GXP into the high growth areas in Porirua, Waitangirua, Mana and Plimmerton;
- Alleviates capacity constraints at Waitangirua, Porirua, Mana and Plimmerton.
- Relieves loading constraints due to the capacity of the Pauatahanui GXP 110/33 kV transformers;
- Targeted distribution augmentation projects alleviate issues within the Ngauranga 11 kV network; and
- Defers age based replacement of assets by reducing utilisation and criticality.

The risks associated with this option are:

- Requires significant financial and time investment to establish a new zone substation; and

- The investment profile during the planning period is not uniform, and is instead clustered around two years of investment required for each zone substation project.

The estimated cost of this network development option is shown in Table 8-30.

Project Description	Cost ($M)
New Pauatahanui Zone Substation & additional network reinforcement	10.9
Common Projects for all options (communication & protection links + common cable reinforcements)	3.1
Total NW Area NDRP Investment - Option 2	**14.3**
Additional condition-based asset renewal projects required under Option 2*	3.0

Table 8-30 Estimated Cost of Network Development Option 2

*Note: The asset renewal expenditure under Options 2 and 4, used in the NPV analysis is $3 million. This is lower than accounted for in Options 1 and 3 ($5.7 million), as it reduces the criticality of a number of assets in the North, allowing capital expenditure deferral.

Option 3: Grenada Zone Substation and Whitby/Aotea Network Augmentation

This option includes installation of a new zone substation at Grenada. This station will be supplied from Takapu Road GXP and established on a section of land in Grenada North, which has been pre-designated for construction of a new zone substation. This zone substation will have feeders interconnecting with highly loaded feeders from Ngauranga, Johnsonville and Tawa.

A number of distribution level works will be implemented to overlay undersized cable segments and improve feeder capacity at Ngauranga as well as to reinforce the distribution ring supplying the Porirua city centre. Transformer replacement will be required at Mana and Plimmerton by 2020 and Waitangirua by 2021.

To provide subtransmission supply to a new Grenada zone substation, the three options available are:

1. Installation of a 33 kV switching station to provide a 33kV bus to the new zone substation via from the TKR-NGA sub transmission circuits. This tee-off will supply 2x24 MVA transformers at the Grenada zone substation. The incremental cost of these works is expected to be $4.4 million on top of the zone substation development;

2. Directly tee-off the TKR-NGA sub transmission circuits via fused disconnects or solid links, similar to the Tawa/Kenepuru tee-off. This tee-off will supply 2x24 MVA transformers at the Grenada zone substation. The incremental cost of these works is expected to be $3.4 million; or

3. Install new sub transmission cabling from Takapu Road. These new cables will supply two new 24 MVA transformers at the Grenada zone substation. The incremental cost of these works is expected to be $5.4 million.

The recommended option is to install a 33 kV switching station to provide a 33kV bus to the new Grenada zone substation from the TKR-NGA sub transmission circuits.

Installation of a new zone substation in the Grenada area allows reduction in Ngauranga zone substation load to either reduce the utilisation of the Ngauranga transformers or to allow eventual decommissioning.

The demand at Pauatahanui GXP is constrained by the capacity of the 110/33 kV transformers. WELL will need to initiate a project with Transpower to replace these transformers with higher rated units within as part of this option.

Figure 8-39 provides a visual representation describing the final network configuration from the development path.

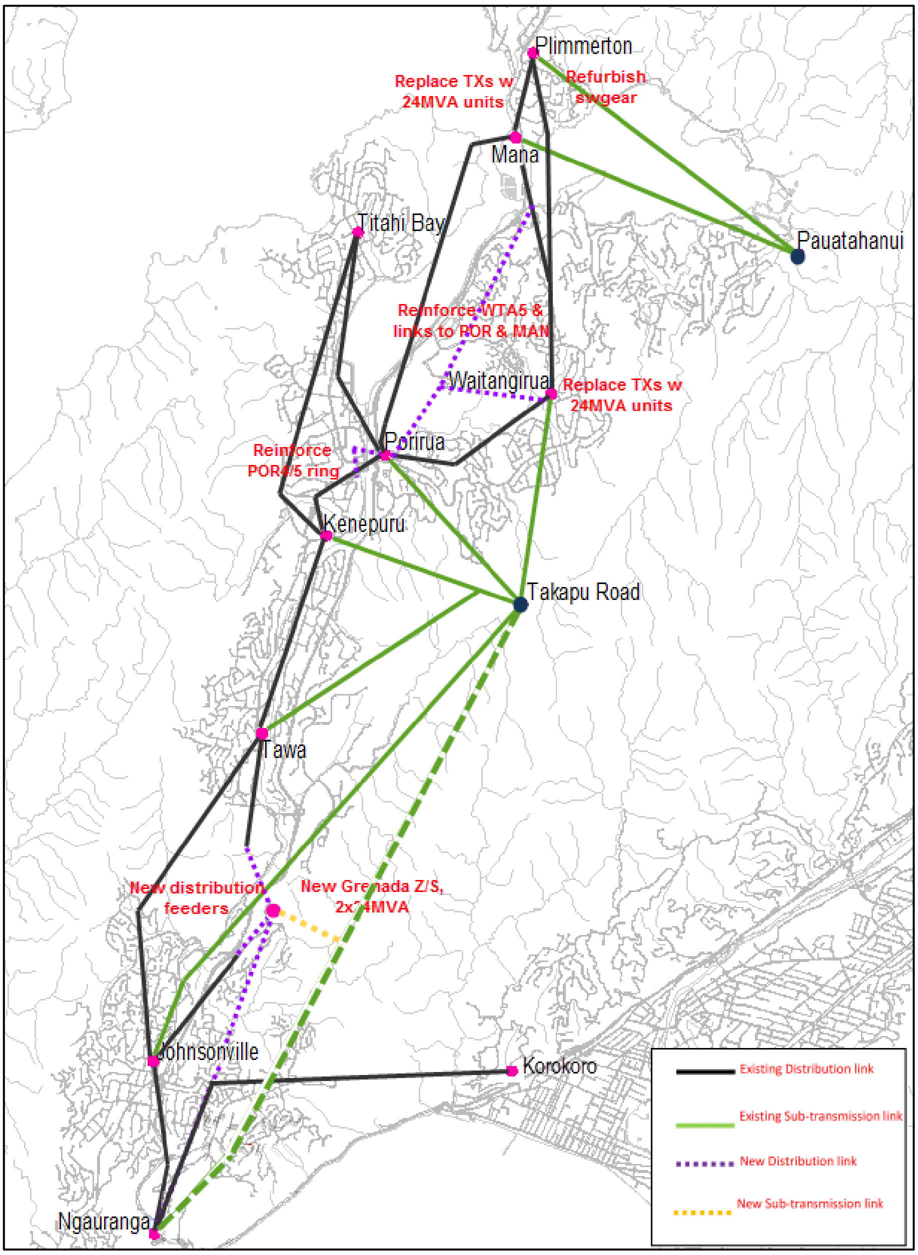


Figure 8-39 Network Configuration Option 3

The benefits of this option are:

- Introduces a new connection point into the high growth areas in Grenada;
- Alleviates capacity constraints at Ngauranga due to Grenada residential developments;
- Targeted distribution augmentation projects to alleviate issues within Waitangirua, Porirua, Mana and Plimmerton 11 kV networks; and

- Offers the opportunity to decommission Ngauranga zone substation, avoiding costly asset renewal at this site.

The risks associated with this option are:

- Requires significant investment to establish a new zone substation
- The investment profile during the planning period is not uniform, and is instead clustered around two years of investment; and
- Significant distribution augmentation and asset replacement is still required at Waitangirua, Porirua, Mana and Plimmerton.

The estimated cost of this network development option is shown in Table 8-31.

Project Description	Cost ($M)
New Grenada Zone Substation & additional network reinforcement	21.6
Common Projects for all options (communication & protection links + common cable reinforcements)	3.1
Total NW Area NDRP Investment - Option 3	**24.7**
Additional condition-based asset renewal projects required under Option 3	5.7

Table 8-31 Estimated Cost of Network Development Option 3

Option 4: Pauatahanui Zone Substation and Grenada Zone Substation

This option involves installation of two new zone substations, one in Grenada and the other in the Pauatahanui/Whitby area. These new stations provide for the expected growth in the Porirua basin as well as relieving all current constraints.

The new zone substation at Pauatahanui will defer replacement of the transformers at Waitangirua, Mana and Plimmerton outside of the planning period while the new zone substation at Grenada offers the opportunity to partially or completely offload the Ngauranga zone substation. Replacement of the Ngauranga transformers will be driven by condition and may be deferred till the end of the planning period.

A number of smaller projects are enacted around these works to alleviate localised distribution level constraints, replace aging assets and improve security of supply.

Figure 8-40 provides a visual representation describing the final network configuration from the development path.

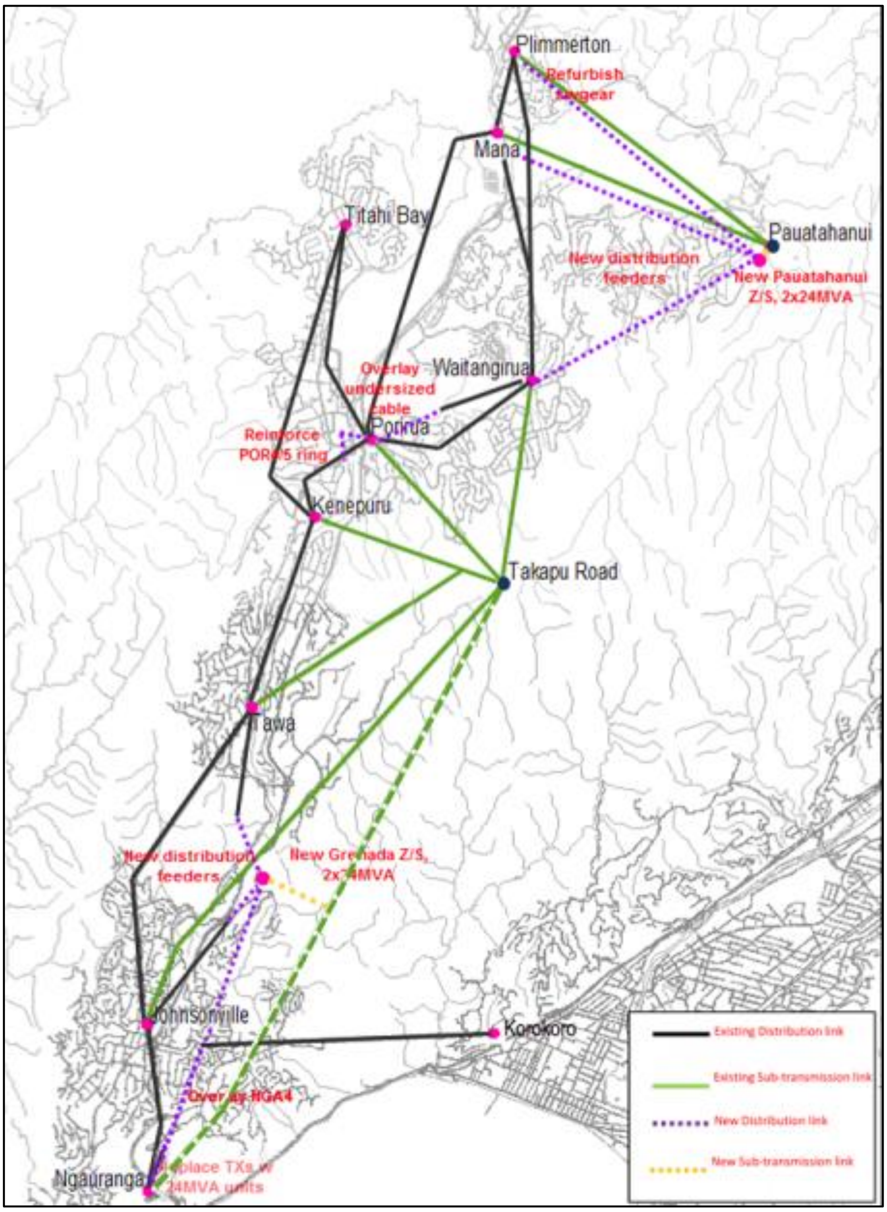


Figure 8-40 Network Configuration Option 4

The benefits of this option are:

- Introduces new connection points into the high growth areas in Grenada, Porirua, Waitangirua, Mana and Plimmerton;
- Relieves loading constraints due to the capacity of the Pauatahanui GXP 110/33 kV transformers;
- Defers age based replacement of assets at Ngauranga, Waitangirua, Mana and Plimmerton by reducing utilisation and criticality; and
- Caters for long term network growth in the Northwestern area.

The risks associated with this option are:

- Requires significant investment to establish two new zone substations; and

- The investment profile during the planning period is not uniform, and is instead clustered around two years of investment required for each zone substation project.

The estimated cost of this network development option is shown in Table 8-32.

Project Description	Cost ($M)
New Pauatahanui Zone Substation	7.2
New Grenada Zone Substation & additional network reinforcement	12.5
Common Projects for all options (communication links + common cable reinforcements)	3.1
Total NW Area NDRP Investment - Option 4	**22.8**
Additional condition-based asset renewal projects required under Option 4	3.0

Table 8-32 Estimated Cost of Network Development Option 4

8.5.4 The Northwestern Area Development Plan

The most cost effective solution which mitigates all identified issues while also ensuring optimised network capacity and security of supply is Option 2: Installation of a new zone substation in the North (1b) and augmentation in the South (2a).

Option 2 involves the following discrete milestones and timing of works to mitigate the identified constraints in the most feasible and cost-effective manner:

- **2019** – Open point shifts will be enacted to alleviate a number of distribution constraints at Tawa, Porirua and Ngauranga;

- **2020** – Reinforce Porirua CBD ring by increasing meshing. A new cable can be installed between 17 Parumoana Street and 14 Parumoana Street. This project will likely be initiated by any customer connections which result in the planning criteria of the Porirua CBD ring being exceeded;

- **2021** – Install a new feeder from Porirua zone substation to reinforce the Porirua CBD ring and provide additional supply security and capacity for projected growth due to the Porirua city centre revitalisation initiative;

- **2021-2022** – Replace the transformers at Ngauranga with higher capacity units. The existing transformers are at an advanced age and constrain capacity for growth in the Johnsonville, Newlands, Woodridge and Grenada areas, however this option may change subject to Transpower's TKR – NGA 110kV line upgrade plan;

- **2022-2023** – Install a new zone substation to supply load in the Whitby and Aotea areas. This new zone substation would consist of a new 11 kV bus in the vacant land adjacent to the Pauatahanui GXP. The existing Pauatahanui 110/33 kV transformers are at an advanced age and constrain capacity for growth. A customer project will be initiated to replace these units with new 110/33/11 kV transformers providing at least 50 MVA of N-1 capacity; and

- **2024** – Open point shifts will be enacted to alleviate a distribution constraint within the Plimmerton distribution network.

The majority of identified feeder overloads will be eliminated by the end of the planning period. Construction of a new zone substation in Grenada, has been deferred in lieu of increasing sub transmission and distribution capacity at Ngauranga by replacing the Ngauranga transformers and reinforcing the distribution network.

The loading issues at Mana / Plimmerton will be mitigated in the short term by demand side management and improving capacity transferability between Mana, Plimmerton, Titahi Bay and Waitangirua.

Loading issue at Johnsonville will be addressed by improving tie points with Ngauranga and Tawa.

8.5.5 Summary of the Northwestern Area Investment

Table 8-33 shows the investment plan for growth and reinforcement projects in the Northwestern area for the planning period from 2019-2028. All sub transmission protection relay and RTU replacement projects are categorised as asset renewal expenditure, as detailed in Section 7.

Year	Project	Estimated Cost ($K)	Comments
2019	Reinforce the Porirua CBD Ring - Stage 1	200	Common Project
	Takapu Road Communications - Stage 2 (2018)	400	Common Project
	Allowance for minor cable reinforcement works	400	Common Project
Year Total		**1,000**	
2020	Allowance for minor cable reinforcement works	300	Common Project
	Titahi Bay cable reinforcement works	300	Common Project
Year Total		**600**	
2021	New Pauatahanui Zone Substation – Stage 1	500	NDP Option 2
	Titahi Bay cable reinforcement works	500	Common Project
	Reinforce the Porirua CBD Ring - Stage 2	1,000	Common Project
	Allowance for minor cable reinforcement works	300	Common Project
Year Total		**2,300**	
2022	New Pauatahanui Zone Substation – Stage 2	1,500	NDP Option 2
	Replace the Ngauranga Transformers – Stage 1	1,700	NDP Option 2
	Allowance for minor cable reinforcement works	200	Common Project
Year Total		**3,400**	
2023	New Zone Substation distribution links to	1,700	NDP Option 2

Year	Project	Estimated Cost ($K)	Comments
	Waitangirua and Mana/Plimmerton – Stage 1		
	Replace the Ngauranga Transformers – Stage 2	2,500	NDP Option 2
	Allowance for minor cable reinforcement works	500	Common Project
Year Total		**4,700**	
2024	New Zone Substation distribution links to Waitangirua and Mana/Plimmerton – Stage 2	1,400	NDP Option 2
	Titahi Bay cable reinforcement works	700	Common Project
	Allowance for minor cable reinforcement works	500	Common Project
Year Total		**2,600**	
2025	Allowance for minor cable reinforcement works	500	Common Project
	New Zone Substation distribution links to Waitangirua and Mana/Plimmerton – Stage 3	500	NDP Option 2
Year Total		**1,000**	
2026	Allowance for minor cable reinforcement works	**500**	Common Project
2027	Allowance for minor cable reinforcement works	**500**	Common Project
2028	Allowance for minor cable reinforcement works	**500**	Common Project
	Total Investment	**17,100**	

Table 8-33 Summary of Northwestern Area Growth Investment Requirement ($K in constant prices)

8.6 Northeastern Area NDRP

Figure 8-41 The Hutt Valley[58]

This section provides a summary of the Northeastern Area NDRP. This section is structured as follows:

- Identified GXP development needs;
- Identified sub transmission and distribution level development needs and options;
- The network development plan for the planning period; and
- A summary of the expected expenditure profile.

8.6.1 GXP Development

The Northeastern area is supplied from four GXPs. Gracefield and Upper Hutt provide sub transmission 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 8-34.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Maximum Demand (MVA)	
			2018	2028
Gracefield 33 kV	2x 85	89 / 89	59	67
Haywards 33 kV	1x 20	27 / 28	14	18
Melling 33 kV	2x 50	54 / 55	30	31
Upper Hutt 33 kV	2x 40	51 / 53	28	31

[58] Photography credit: Hutt City Council

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Maximum Demand (MVA)	
			2018	2028
Haywards 11 kV	1x 20	23 / 23	17	19
Melling 11 kV	2x 25	28 / 28	24	23
Total (after diversity)	-	-	**171**	**187**

Table 8-34 Northeastern Area GXP Capacities

Gracefield

There are two transformers at Gracefield which provide 33 kV supply to four WELL zone substations (Wainuiomata, Gracefield, Seaview and Korokoro). There are no capacity and security constraints at Gracefield as the sustained peak demand at this GXP is below the N-1 supply transformer capacity.

Haywards

Haywards supplies Trentham zone substation via a 33 kV outdoor bus and a single 20 MVA 110/11 kV transformer in parallel with a 5 MVA 33/11 kV transformer supply an 11kV switchbboard. The loss of either of the 110/33 kV or 110/11 kV supply transformers has a significant impact on system security.

Transpower is in the process of installing three-winding 60/30/30 MVA transformers to provide N-1 security for both 11 kV and 33 kV supplies. The final configuration of the new transformers has been confirmed and this requires minor modifications for the Wellington Northeastern network.

Upper Hutt

The Upper Hutt GXP comprises two parallel 110/33 kV transformers nominally rated at 37 MVA each, supplying a 33 kV bus that feeds zone substations at Brown Owl and Maidstone through underground 33 kV fluid-filled cables.

Transpower has completed a project to replace the existing Upper Hutt GXP 33 kV outdoor bus with an indoor switchboard. In 2019 WELL has scheduled work to install new RTUs at Brown Owl and Maidstone and will complete sub-transmission protection upgrade after new RTUs are commissioned. New protection equipment will interface with the recently commissioned Transpower equipment.

Melling

The Melling GXP comprises two parallel 110/33 kV transformers nominally rated at 50 MVA each, 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 nominally rated at 30 MVA each.

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 Sub transmission and Distribution Development Plans

This section describes the identified security of supply constraints and development needs for the Northeastern Area sub transmission and distribution networks.

8.6.2.1 Sub transmission Development Needs

The Wellington Northeastern network consists of 18 sub transmission 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 8-35.

Zone Substation	Transformer Firm Capacity (MVA)	Single Incoming Circuit Capacity (MVA)		Peak Season	Sustained Peak Demand (MVA)		Date constraints are binding and season constrained	ICP counts as at 2018
		Winter	Summer		2018	2028		
Existing constraints								
Wainuiomata[59]	16.5	21	14	Winter	19	20	Existing Winter constraint	7,155
Forecasted constrains								
Korokoro	23	21	21	Winter	20	23	2023 Winter constraint (21)	4,032
Not Constrained								
Brown Owl	18.4	22	16	Winter	15	15	Not Constrained	6,530
Gracefield	23	20	15	Winter	12	12	Not Constrained	2,732
Maidstone	22	19	14	Winter	14	17	Not Constrained	4,219
Naenae	18.4	22	18	Winter	15	16	Not Constrained	6,416
Seaview	22	18	13	Winter	14	13	Not Constrained	3,444
Trentham	23	23	17	Winter	14	18	Not Constrained	5,548
Waterloo	23	23	14	Winter	16	16	Not Constrained	6,044

Table 8-35 Northeastern Area Zone Substation Capacities

[59] N-1 capacity at Wainuiomata zone substation is constrained by the rating of the relocated 20 MVA transformer from Petone

Wainuiomata

The sustained peak demand supplied by Wainuiomata currently exceeds transformer N-1 capacity of the zone substation. This is illustrated in Table 8-36.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @2018 (MVA)	Minimum off load for N-1 @ peak (MVA)
Wainuiomata 1	Winter	16.5	19.6	3.1
	Summer	14.2	16.6	2.4
Wainuiomata 2	Winter	16.5	19.6	3.1
	Summer	14.2	16.6	2.4

Table 8-36 Wainuiomata Substation Constraints

Figure 8-42 shows the load duration curve against the N-1 cyclic ratings of transformer and sub transmission cables for Wainuiomata. The load duration curves shows that at present the demand exceeds the firm capacity less than 1.5% 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.

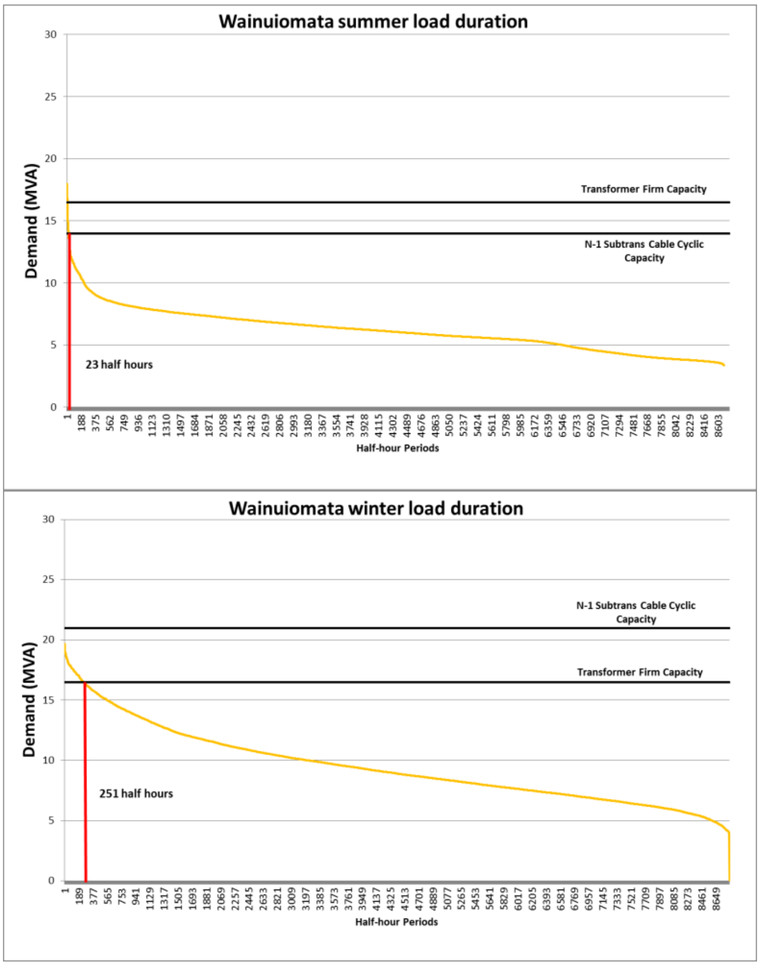
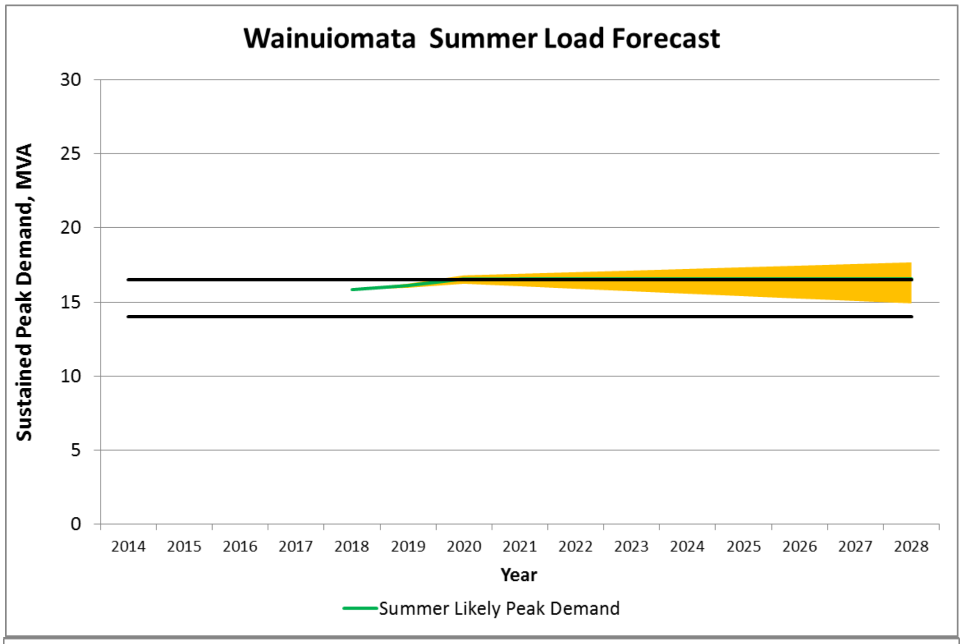


Figure 8-42 Wainuiomata Load Duration

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 8-43.



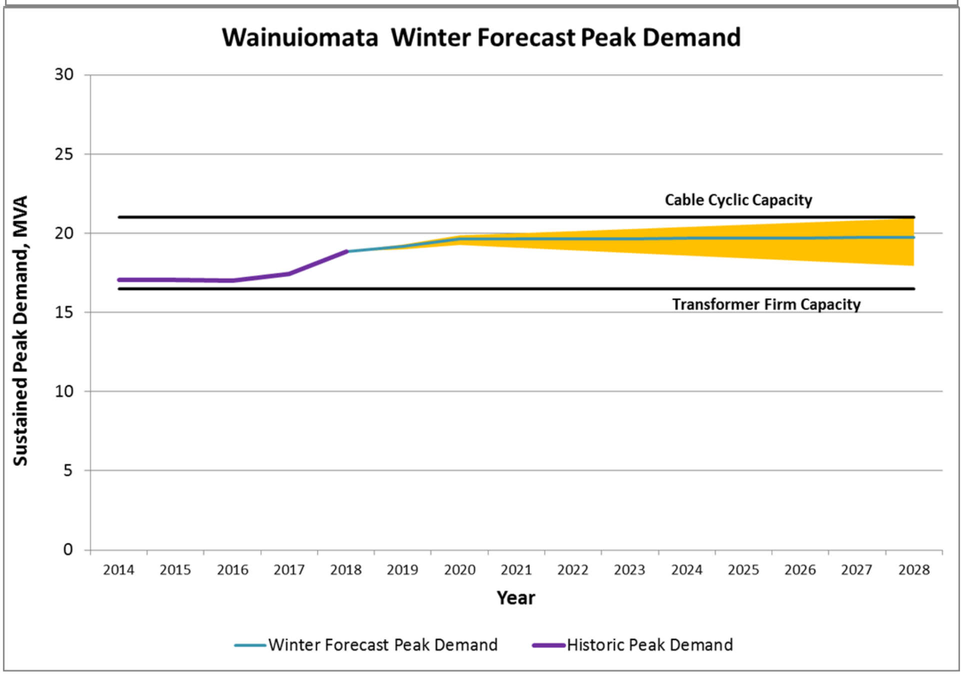


Figure 8-43 Wainuiomata Load Forecast

Korokoro

At present, maximum demand at Korokoro is within available N-1 sub transmission capacity. The peak demand at Korokoro is expected to slightly exceed the 33 kV incomer cable in winter 2023.

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2023 (MVA)	Minimum off load for N-1 @ peak (MVA)
Korokoro A	Winter	21.3	21.4	0.1
	Summer	20.6	18.0	0

Circuit	Season	Constraining N-1 Cyclic capacity (MVA)	Sustained Peak Demand @ 2023 (MVA)	Minimum off load for N-1 @ peak (MVA)
Korokoro B	Winter	21.3	21.4	0.1
	Summer	20.6	18.0	0

Table 8-37 Korokoro Sub transmission Capacity Shortfall

Based on the estimated growth scenarios and development within the planning period, the sustained peak load at Korokoro is forecasted as shown in Table 8-37. We will continue monitoring load growth and manage the overloading risk through operational control.

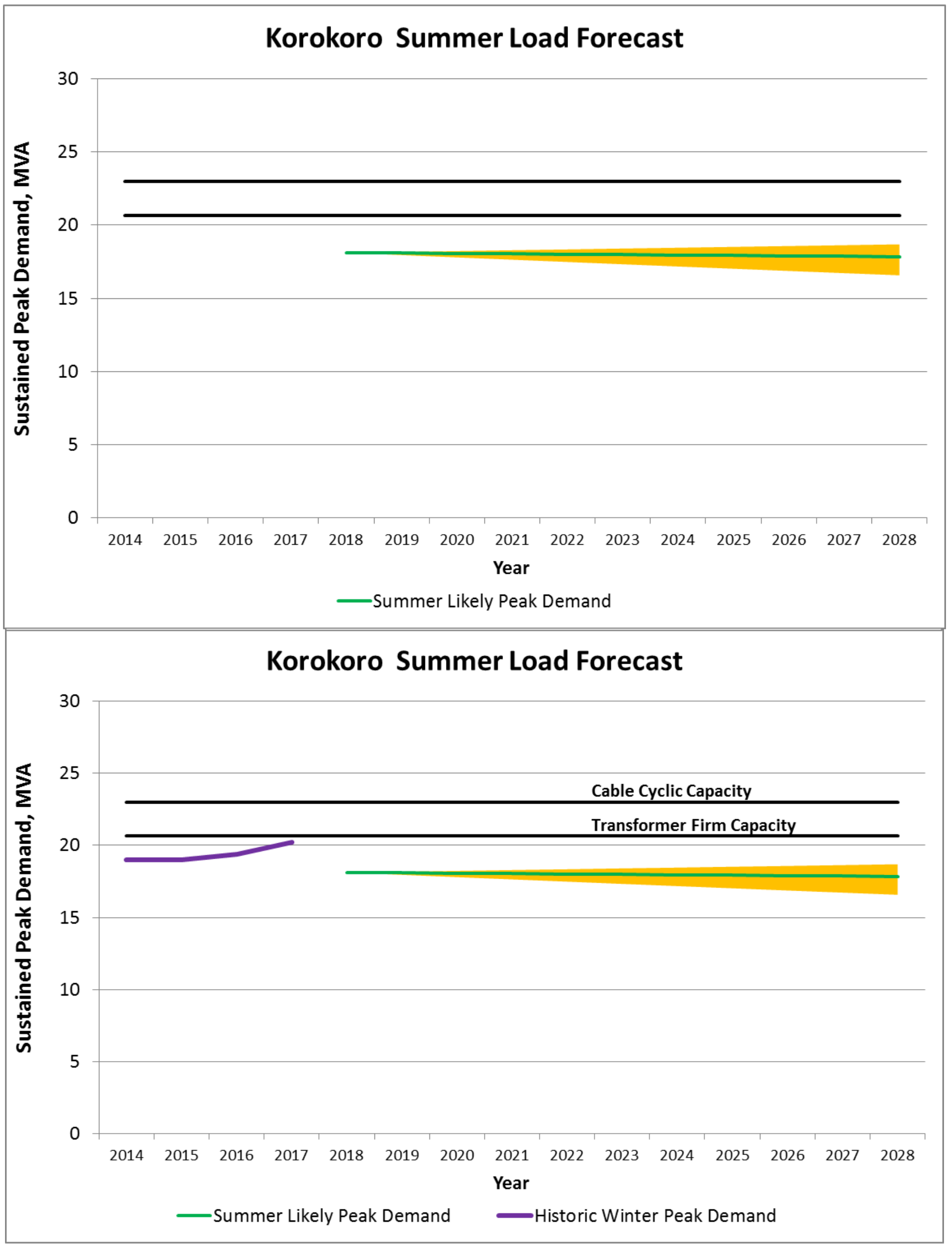


Figure 8-44 Korokoro Load Forecast

8.6.2.2 Distribution Level Development Needs

The most critical distribution level issues are those associated with overload radial feeders supplying critical loads. Table 8-38 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	Control
Current							
BRO CB8	Radial	Brown Owl	419 m	69%	79%	1,519	Network augmentation
HAY CB2722[1]	Radial	Haywards (GXP)	1,484 m	77%	78%	1,598	Network augmentation
Within 5 Years							
MAI CB6	Radial	Maidstone	439 m	65%	69%	773	Monitor growth

Table 8-38 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.

8.6.3 Northeastern Network Development Plan

More work will be undertaken to develop a comprehensive Northeastern development plan in 2019.

For budgeting purposes, an allowance has been included for various distribution level works. This allowance has been provisioned from 2019 onwards and will be subject to any consumer driven step change load growth in the area and to mitigate the constraints at Korokoro. The allowance is estimated based on the average distribution level reinforcement costs for a year and provides for:

- Overlay of approximately 400 m of undersized 11 kV cable including trenching, traffic management and reinstatement costs; and
- Installation of approximately 600 m of new distribution links between zones at 11 kV.

All legacy growth and reinforcement projects planned for the Northeastern area and detailed in previous AMPs have been completed or are deferred in lieu of a consolidated strategy which will be provided by the forthcoming Northeastern area NDRP.

Table 8-39 shows the investment plan for growth and reinforcement projects in the Northeastern Area for the planning period.

Year	Project	Estimated Cost ($K)	Comment
2019	Reinforcement to alleviate constraints at Korokoro and Wainuiomata – Stage 1	600	Common Projects
	Transpower HAY 33kV and 11kV upgrade associated projects	400	Common Projects
Year Total		**1,000**	

Year	Project	Estimated Cost ($K)	Comment
2020	Reinforcement to alleviate constraints at Korokoro and Wainuiomata – Stage 2	**500**	Common Projects
2021	Allowance for minor cable reinforcement works	**500**	Common Projects
2022	Allowance for minor cable reinforcement works	**500**	Common Projects
2023	Allowance for minor cable reinforcement works	**500**	Common Projects
2024	Allowance for minor cable reinforcement works	**500**	Common Projects
2025	Allowance for minor cable reinforcement works	**500**	Common Projects
2026	Allowance for minor cable reinforcement works	**500**	Common Projects
2027	Allowance for minor cable reinforcement works	**500**	Common Projects
2028	Allowance for minor cable reinforcement works	**500**	Common Projects
	Total Investment	**5,500**	

Table 8-39 Summary of Northeastern Area Investment Requirement ($K in constant prices)

8.7 Customer Initiated Projects and Relocations

These projects have been aggregated in the budget in accordance with the categories discussed below. Overall, the budgeted expenditure for 2019 is $8.03 million. Consumer and developer confidence and the Chorus UFB roll out activity remains high compared with recent years.

8.7.1 New Connections

For the sixth consecutive year the number of residential building consents issued in the Wellington region has risen, driven by the growth in apartments within the Wellington CBD and subdivision growth along the northern belt. Figure 8-45 shows the number of building consents issued for new houses and apartments over the last seven years. This is expected to decline over time.

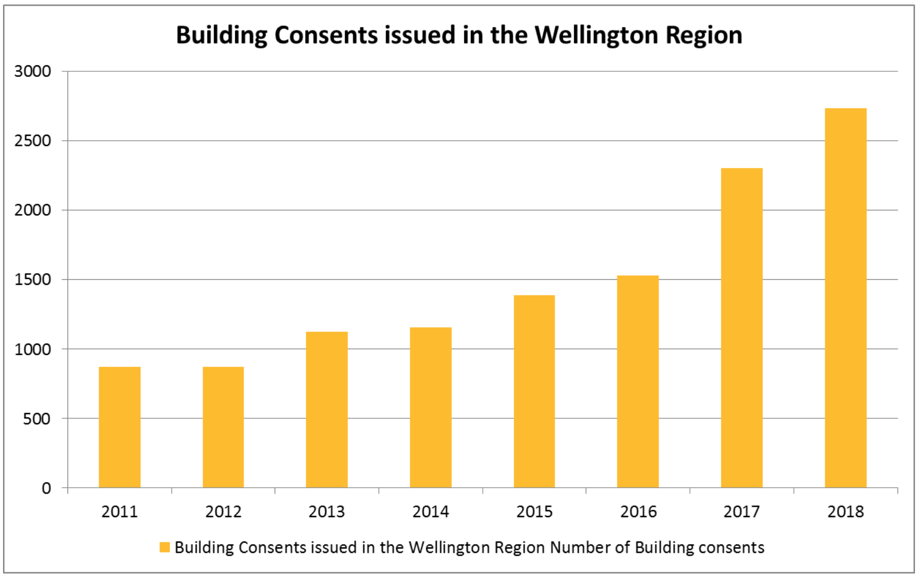


Figure 8-45 Number of Building Consents Issued in the Wellington Region

8.7.2 Substations

Budgeted spend of $4.3 million for 2019 includes a $2.0 million allowance for two large individual development projects in Upper Hutt (MPI and Rivera). Excluding this, the remaining forecast spend of $2.2 million is in line with the past three years.

8.7.3 Subdivisions

While 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 increasing, particular in the northern areas of Wellington and Porirua cities. This is partially offset by industrial property development which has slowed, and the shortage of vacant sites that can be easily converted to meet tenancy needs. The budget allocation for subdivisions in 2019 is $2.4 million.

8.7.4 Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included within the customer substation area of the customer connection forecasts.

8.7.5 Relocations

An allowance in 2019 of $2.5 million for relocation and undergrounding work, initiated from NZTA and TLAs, as well as other customer initiated relocations, has been made. Transmission Gully and redevelopment of a major SH2 intersection are critical projects in this category as well as costs associated with the Chorus UFB roll out.

8.7.6 Consumer Connections

The total forecast consumer connection capital expenditure for 2019 to 2029 is presented in Table 8-40.

Consumer Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Substation	4,289	4,356	4,356	4,708	4,732	4,756	4,779	4,803	4,827	4,827
Subdivision	2,379	2,496	3,475	4,087	4,100	4,044	4,125	4,208	4,292	4,378
High Voltage Connection	133	136	139	141	144	147	150	153	156	156
Residential Consumers	1,127	1,154	1,170	1,198	1,215	1,244	1,262	1,292	1,310	1,310
Public Lighting	100	100	100	100	100	100	100	100	100	100
Total	**8,028**	**8,242**	**9,240**	**10,234**	**10,291**	**10,291**	**10,416**	**10,556**	**10,685**	**10,771**

Table 8-40 Consumer Connection Capital Expenditure Forecast ($K in constant prices)

8.7.7 Asset Relocations

The forecast asset relocation capital expenditure, primarily related to roading projects, is presented in Table 8-41.

Programme	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Roading Relocations	2,450	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029
Total	**2,450**	**1,783**	**1,801**	**1,819**	**1,837**	**1,874**	**1,912**	**1,950**	**1,989**	**2,029**

Table 8-41 Asset Relocation Capital Expenditure Forecast
($K in constant prices)

8.8 Summary of the Capital Expenditure Forecasts

From the details in the sections above, WELL's network development and growth capital expenditure forecast is summarised in the table in Table 8-42.

Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Southern Area	4,000	4,360	3,300	1,900	1,500	400	500	2,100	2,200	500
Northwestern Area	1,000	600	2,300	3,400	4,700	2,600	1,000	500	500	500
Northeastern Area	1,000	500	500	500	500	500	500	500	500	500
System Growth & Reinforcement Total	**6,000**	**5,460**	**6,100**	**5,800**	**6,700**	**3,500**	**2,000**	**3,100**	**3,200**	**1,500**

Table 8-42 Capital Expenditure Forecasts
($K in constant prices)

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Section 9

Emerging Technology

9 Emerging Technology

This chapter is a summary of WELL's strategy for emerging technologies and is based on the detailed development plan, '*WELL Network Development and Reinforcement Plan – Emerging Technology'*. The strategy sets out WELL's approach to the adoption of emerging technologies over the next 10 years. It was developed with knowledge obtained from trial projects and collaborations with external partners and colleagues within CK Infrastructure Holdings Ltd.

Distributed Energy Resources (DER) will significantly increase the energy choices for end use consumers. Adoption of DER will also change the way the electricity distribution network is operated, changing from a single power flow to a multi-flow system. Customers will have a choice to have greater interaction with the electricity sector by offering and coordinating their energy resources through storing, generating, consuming or discharging back onto the network. EVs will increase energy demand across the network when they plug in to charge. Steps are already underway to signal (through cost reflective prices) when the network is less congested.

Whether customers adopt DER and/or EVs, network owners will require investment to improve visibility of the LV network to monitor power quality and signal where DER can support the quality, reliability and security of the network. Many of the DER services will be provided from retailers and load aggregators as they respond to network signals to utilise customer DER assets for support or curtailment. This will require clearer standards for network operating limits to be communicated to participants in the supply chain. It is important that all users of DER assets understand their individual responsibilities associated with these standards. This approach will ensure acceptable voltage and frequency ranges can be maintained for all customers and avoid situations where the network becomes disrupted.

Additional investment will be required to introduce LV monitoring technology to provide visibility of impacts from customer DER. This information can used to forecast when retailers and load aggregators need to coordinate "behind the meter" DER interaction to support the network operating to defined standards. 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.

New technology could also 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.

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:

q) **New technology standards:** Introduce new standards for new technology, allowing better and lower cost integration;

r) **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;

s) **Congestion standards**: Introduce standards on how congestion is defined and require network congestion to be disclosed;

t) **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;

u) **Management of distributed resources:** Investigate and trial a platform that enables the management of distributed energy resources;

v) **Support with efficient prices:** Introduce efficient prices that reflect the benefits and encourage the use of disruptive technology;

w) **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

x) **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. This approach is driven from scenario analysis and presents a prudent and flexible approach to manage uncertainty, while avoiding over-build 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.

9.1.1 Funding Assumptions and Future Funding Decisions

Currently, WELL is funded by a Streamlined Customised Price Path (SCPP) which expires in 2021. WELL will then move back to 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 AMP supports the capital forecasts with supporting analysis and information, providing evidence as to why the capital expenditure is needed. The SCPP also includes additional funding for WELL's earthquake readiness programme. The supporting evidence for the additional capex was provided as part of the SCPP application.

WELL's approach to including funding for new technology in the AMP is consistent with this approach. Funding the capability to monitor and manage distributed energy resources will 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. For this reason, the AMP does not include funding for:

a) 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. We think this should be delivered by a cheaper solution such as the role out of an enhanced consumer owned smart meter where one meter at the consumer's house meets the industry as well as the consumer's needs;

b) 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;

c) Long term network reinforcement cost via traditional solutions to accommodate significant demand changes due to uncertainties in the uptake of the emerging technology; or

d) The impact that an exponential uptake in EVs might have on demand.

9.1.1.1 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 to the existing network to meet the expected exponential increase in energy demand from EV uptake. Figure 9-1 compares the capital required to meet expected impact 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.

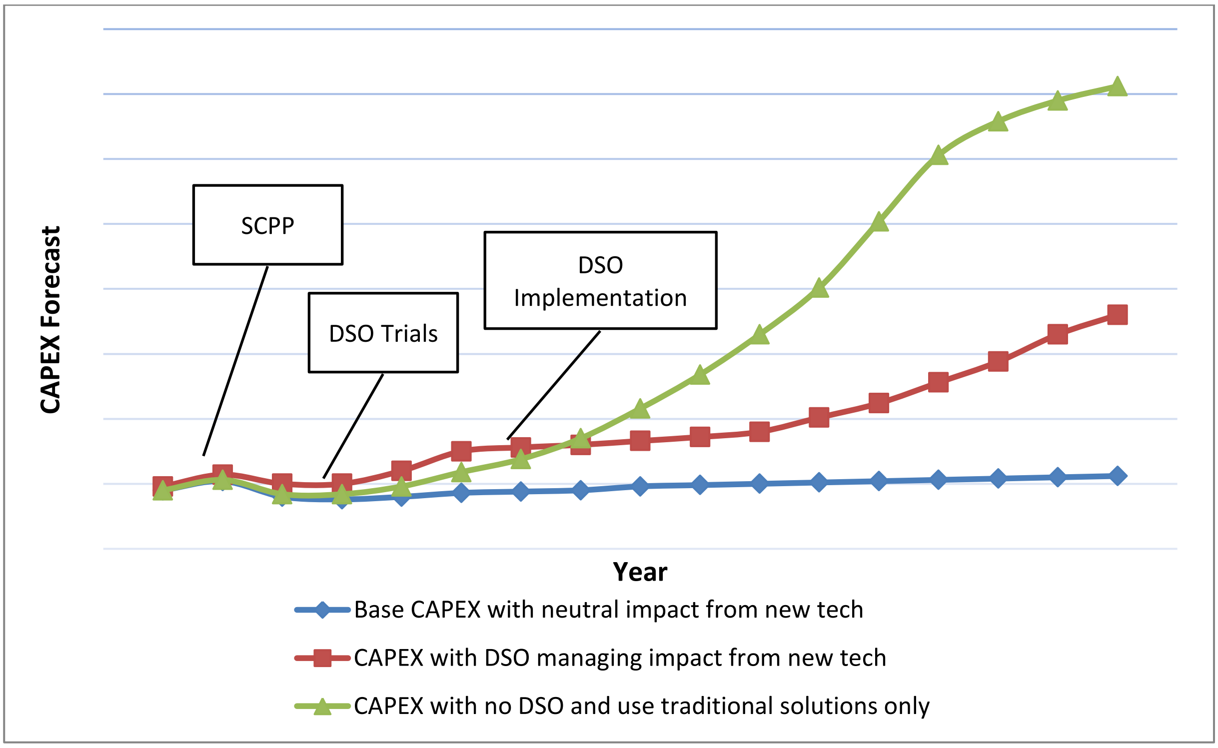

Figure 9-1 CAPEX Forecast for Different Development Options

WELL's initial analysis indicates that the savings to customers from managing congestion using distributed energy resources could be significant. However the introduction of new technology is risky and the investment is still expected to be significant, even though it's considerably less than building traditional capacity.

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 trailed. This AMP includes a range of trials which will test the viability and effectiveness of using distributed energy resources to manage congestion.

The funding for the trials has been included in the AMP. The trails will cost around $2-3 million per annum. A detailed description of the trials, what part of the proposed solution the trial is testing and the cost forecasts for each trail are provided in this section. Once the trials have been completed, WELL will develop a full business case and associated funding requirements which will then be used to inform the AMP.

9.1.1.2 The Future Funding Model

Network capital expenditure under the Default Price Path (DDP) methodology is limited to 120% of the last 10 years average expenditure.

If EDBs require higher levels of funding outside of the DPP constraints then under the current rules they will need to apply for a customised price path (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 in capacity to meet increasing electricity consumption as vehicles change from petrol and diesel fuel to electricity and this increase in capacity will become business as usual for most EDBs.

9.2 Background

Emerging technologies and other factors driving changes in the energy sector will have varying impact on the electricity network, such as:

- Increased demand due to electrification of transportation and industrial processes;
- 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.[60]

The development plan is consistent with views of the Business New Zealand Energy Council that defines three major themes for change in the energy industry:

- Digitalisation;

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[60] Industry regulators have indicated desire to enable adoption of emerging technologies, which may lead to changes in the regulatory requirements, e.g.:

- In October 2018 the Commission: published their findings following an exercise to understand the impact of emerging technologies on the monopoly parts of the electric sector;
- The Authority in their August market commentary indicated they will address barriers to the efficient operation of new technologies in the Code, and encourage adoption of approaches that support emerging technologies.

- 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. This becomes more of a problem for other consumers on the LV network where changes have the greatest impact. 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[61], may start to seriously 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 avoid or lessen large network reinforcement requirements. WELL have introduced cost reflective pricing for EV owners to assist in EV uptake and incentivise demand control. The impact will also depend on the concurrent uptake in other technologies such as solar PV.

Figure 9-3 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. Lack of visibility of stress and strain points on the LV network and usage patterns of consumers could lead to network reinforcement requirements should uncontrolled usage occur. In order to avoid such reinforcement requirements, the network operator will require greater visibility of the network and a better understanding of consumer demands.

[61] Government target of 64,000 electric vehicles in New Zealand by 2021

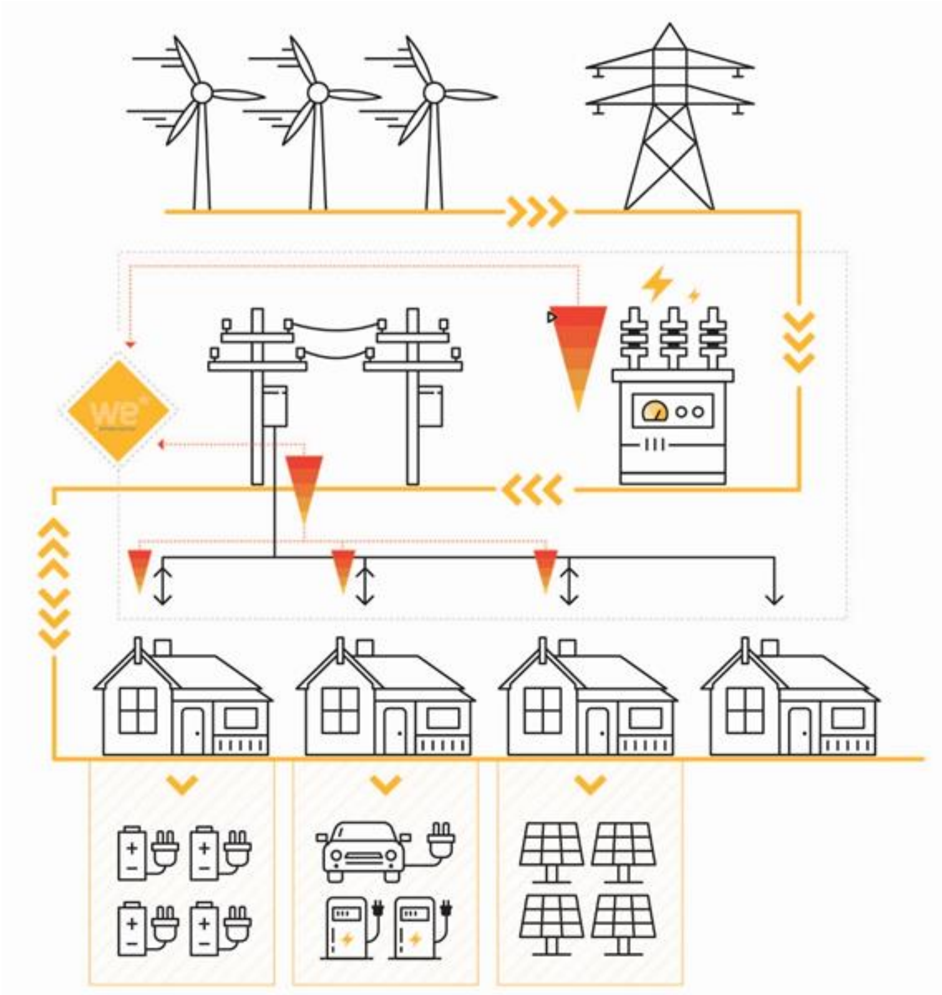

Figure 9-3 Potential Future of the Electrical Network

Depending on the mix of new technology that occurs across the network, there is also an increased risk of stranding network assets. WELL's view is that this will generally not be the case in the Wellington region. There may be small portions of the network where underutilisation may pose risk to capital recoveries over the lifetime of assets, but this will not be the case for the majority of the network.

WELL's strategy to manage this path to becoming a Distribution System Operator (DSO) is to:

- Take a multi-step approach from conceptual DSO to an emergent DSO then finally to a full DSO;
- Use our connections as part of CK Infrastructure Holdings Ltd. to monitor trends globally and similarly leverage connections to New Zealand organisations such as other EDB's, the EEA and ENA to understand national trends;
- Carry out pilot projects in collaboration with retailers, consumers and platform providers to understand how the individual pieces of new technology work and how these should be controlled and optimised. [62] These pilot projects are currently funded out of existing allowances but will require further investment in future years;
- Work with regulators to identify future pathways and regulatory environment changes required to enable easier access and remove arbitrary barriers;

[62] Including management of potentially large amounts of data.

- Work with consumers on new tariffs to promote positive behaviours to respond to price signals and then evolve these tariffs as an important tool to help manage the new technology challenge;

- Signal to stakeholders that an increase in funding may be required in moving to a DSO with greater visibility and control of the network, especially at the 400V level. This has the potential to defer traditional network investment that will be required above the levels signalled in the remainder of this AMP;

- Participate and/or lead a full open collaboration trial in 2019 with stakeholders to inform a business case to move towards a DSO model; and

- Define and set new network policies and connection requirements in regards to new technology adoption to realise new opportunities and control adverse impacts.

9.3 WELL's Innovative Goals

WELL's innovative goal on emerging technologies is applying optimum solutions via emerging technologies, to develop innovative solutions for improving safety, reliability of supply, asset efficiency and avoid unnecessary expenditure.

The primary focus of WELL's new technology advances is to:

- Enable adoption of transformational innovations and be adaptive and responsive to uncertainties in this fast moving environment;

- Adopt new technology that improves safety, reliability of supply, asset efficiency avoids unnecessary expenditure, and the 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.

However, the traditional regulatory frameworks may not adequately support the new EDB business model. Currently there is no additional funding available from the regulatory allowance. WELL needs to work collectively with industry groups, regulators (the Commission and the Authority) to ensure:

- There is adequate funding and incentives for distribution lines companies to explore emerging technologies;

- Efficient allocation of funding for trial projects, and

- Duplication is minimised by knowledge sharing, while maintaining flexibility to ensure compatibility of solutions to individual lines company requirements.

In May 2018 the Commission requested information from regulated EDBs on how they are planning, investing and accounting for emerging technologies. According to the published information[63], EBDs in New Zealand are still at the early stage of exploring emerging technology with research and development (R&D) projects. Across all EBDs, the total spend on emerging technology in 2018 was about 3% of the total regulatory expenditure. The majority of this spend is around energy storage systems and smart grid assets.

9.4 Initiatives

WELL is still at the early stages of strategy development and concept validation on new technologies. Most of the activities planned in this space over the next 2 – 3 years are R&D type projects. These will help form WELL's long term strategy and financial plan setting for the rest of the planning horizon.

To ready the WELL network and organisation for a future enabled by emerging technologies, including facilitating customer choice, WELL will implement strategies to keep abreast of emerging technologies concepts and solutions in eight key areas. These are set out in Figure 9-4 with information in each key area presented below.

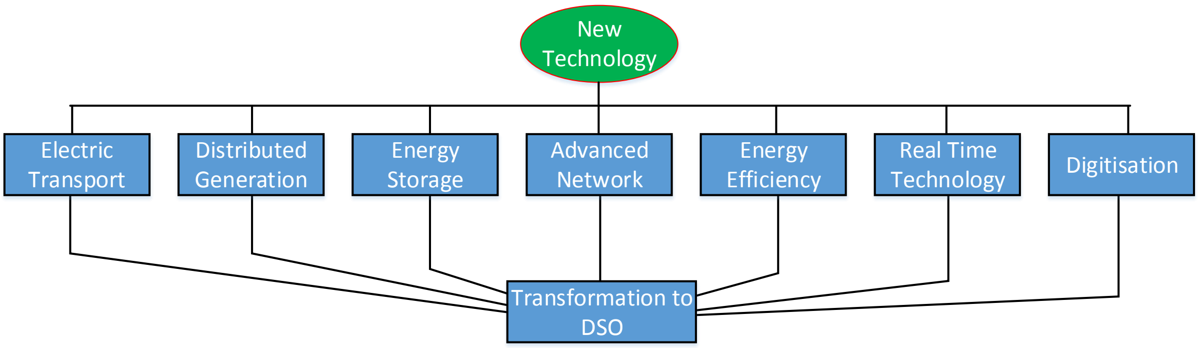

Figure 9-4 Major Development Areas under WELL's New Technology Strategy

9.4.1 Transformation to a DSO

A DSO platform enables an efficient way of managing DERs in a cost effective manner that provides mutual benefits to all stakeholders in the new ecosystem created by emerging technology. Traditionally the single direction power flow does not require EDBs to manage risks from power quality and capacity issues that will be changed due to bi-directional power flow.

WELL's DSO development plan will focus on laying the foundations to prepare for a successful transition to a DSO through innovative projects to develop DSO capabilities across the business. WELL expects the transition to a DSO will not be trivial and will be a long-term goal. It requires investment, including 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 and frequency limits to be within a defined voltage band and frequency band.[64] While EDBs may not be the only available 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.

[63] https://comcom.govt.nz/regulated-industries/electricity-lines/projects/impact-of-emerging-technologies-in-monopoly-parts-of-electricity-sector#projecttab

[64] As required by Electricity (Safety) Regulations 2010

Through collaborations with key stakeholders on an energy balance platform, WELL will take a multi-step approach by exploring the potential of, and ways to control, the risks along the way to become a full DSO. Figure 9-5 shows the stages of transformation from DNO to DSO.

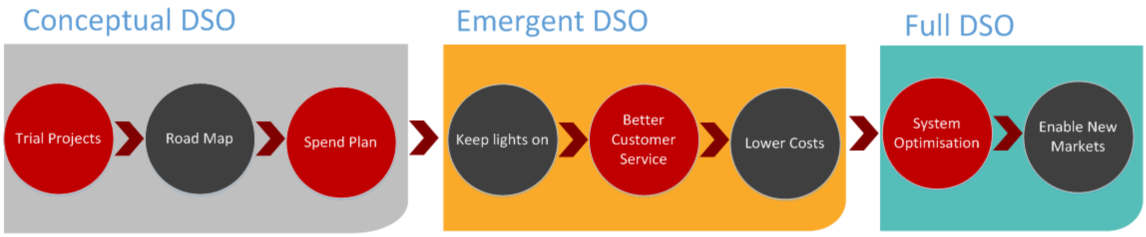

Figure 9-5 DNO-DSO Transformation Stages

Key development areas that require continued focus are to:

- Develop a DSO transformation roadmap that links the development efforts in the next sections. WELL is currently working with ENA on the New Zealand network transformation roadmap and scenario planning with delegations from other New Zealand EDBs;
- Evaluate requirements for retrofitting existing primary plant with smart sensors and communication capabilities to ensure network equipment is ready for flexible operation;
- Understand the new service model of DSO – DNO – TNO – ESO co-ordination platforms and market arrangement through DSO trials. Figure 9-6 and Figure 9-7 show the possible market arrangement options for DSO service operating and commercial models;

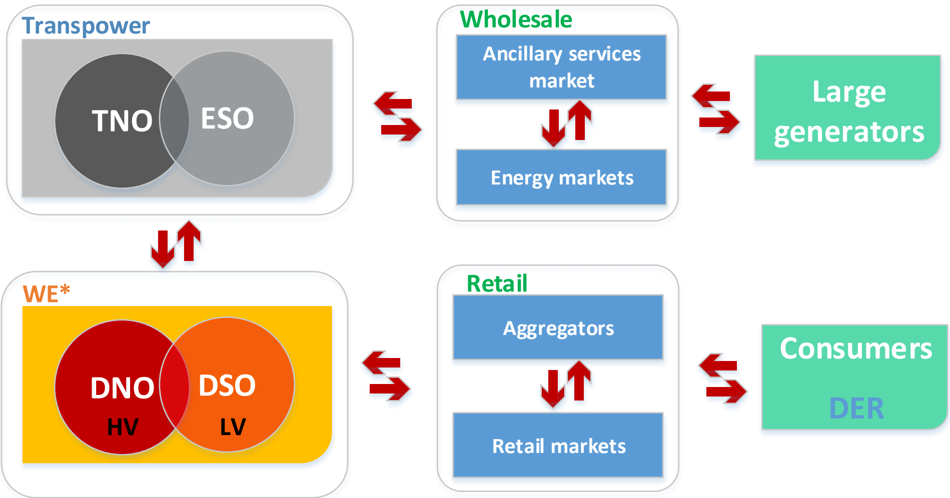

Figure 9-6 A Strawman Proposal for the DSO Service Operating Model

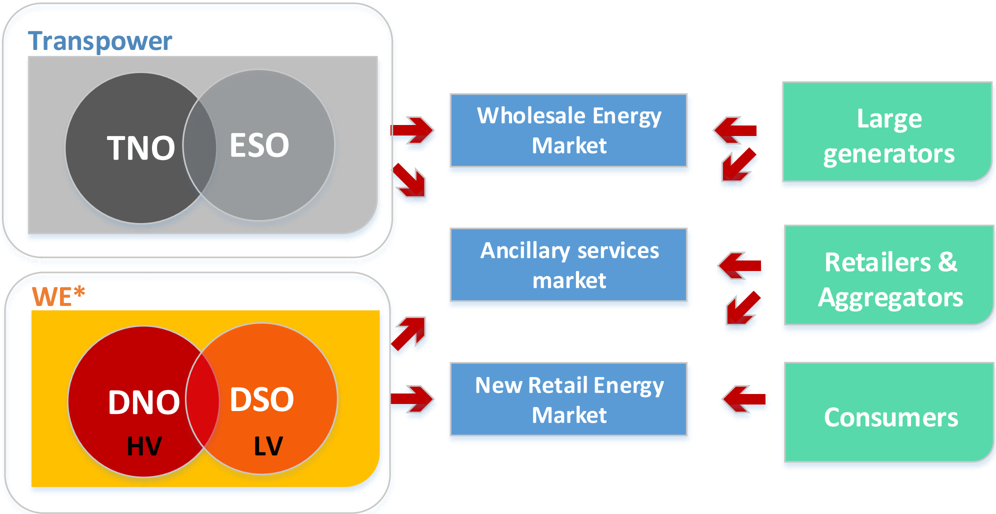

Figure 9-7 Possible Option for the DSO Commercial Model

- Work together with retailers to investigate distributed energy resources and trial load balancing on selected locations:
  - LV feeder balancing
  - HV/LV feeder load balancing between substations: dynamic support between adjacent substations to meet load conditions, which support deferring 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 few micro-grids (see section 9.1.7);
- Design a tariff to be an incentive influencing customer behaviour to support 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;
- Use new technologies as alternatives to conventional solutions (such as upgrade in capacity of primary plant) to achieve much greater efficiency of the network;
- Consider power quality and load balancing. Distributed energy resources enabled by emerging technologies[65] 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. This calls for new market model and operating platforms (network control and trading);
- Integrate corporate information technology (IT)[66] and operational technology (OT)[67]. Historically IT and OT reside in different parts of the organisation however it is vital to integrate these to achieve

[65] The interface of most customer devices and the network will be driven by inverter technologies.

[66] Information technology mostly refers to software applications for commercial decision making, planning, business processes management and resource allocation.

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;

- Change the skills required of WELL's workforce to ensure greater deployment of technologies; and
- Educate consumers on selection of new technology. In terms of the potential benefits consumers could get from new technology appliances, Table 9-1 provides a high level guide of expected functions based on current knowledge.

Appliance Type	Solar panels or wind farm	Battery storage	Battery storage with off grid function	EV with no V2G function	EV with V2G function	More efficient smart appliances
Reduce carbon footprint	✓			✓	✓	✓
Provide grid support		✓	✓	✓	✓	✓
Reduce overall electricity usage	✓					
Transportation				✓	✓	
Improve resilience			✓		✓	
Bi-directional demand response		✓	✓		✓	

Table 9-1 Functions of New Technology Appliances

9.4.2 Electric Vehicles (EVs)

Electrification of the transport fleet is a key focus for New Zealand to achieve the decarbonisation target and has the potential to grow exponentially in the next decade. WELL published the EV study report and key findings[68] to improve communication between stakeholders and WELL, understand the new tariff structure, generate public awareness, and build relationships with suppliers and users. Talking to Early EV adopters and understand their thinking help WELL to form long term strategy.

Some of the other 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): this technology uses car battery to support the bi-directional flow of energy to offset the overall load or even backfeed to grid to support upstream network constraints. The

[67] 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.

[68] Understanding the home charging behaviour of EV customers: https://www.welectricity.co.nz/disclosures/pricing/evtrial/

technology is now proven and ready for market, though not yet commercially available.[69] 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; and

- Regional EV strategy development with key stakeholders in the region. WELL is actively participating in the study and supports the strategic thinking on an EV roll up plan that can bring the most benefit to the region.

The 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[70], this situation is set to change. By proportion of population for the Wellington region, this represents up to 6,000 EVs by 2021 and more than 40,000 EVs by 2028 (assuming a sustained adoption rate). The actual impact of 40,000 EVs connecting to the network at the same time for battery charging, depends on charger types, duration and connection capacity, could be adding more than 100MW to the peak demand if not managed carefully. This will lead to a significant change in our asset planning requirements and infrastructure investment portfolio.

The ability to monitor and manage EV charging is a fundamental part of WEL's DSO development plan and will be essential for responding to this emerging technology.

To proactively build knowledge on how EV charging might impact the network, WELL has already:

- 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

- Run an internal trial with staff using EVs from the corporate fleet after hours to provide information on usage patterns and network demand.

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

- At the LV connection point, there is potential for uneven network distribution due to irregular distribution of EVs across socio-economic groups and locations. Figures 9-8 and 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.

[69] Information from on V2G technology major electric vehicle (EV) manufacturer

[70] http://www.transport.govt.nz/ourwork/climatechange/electric-vehicles/

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.

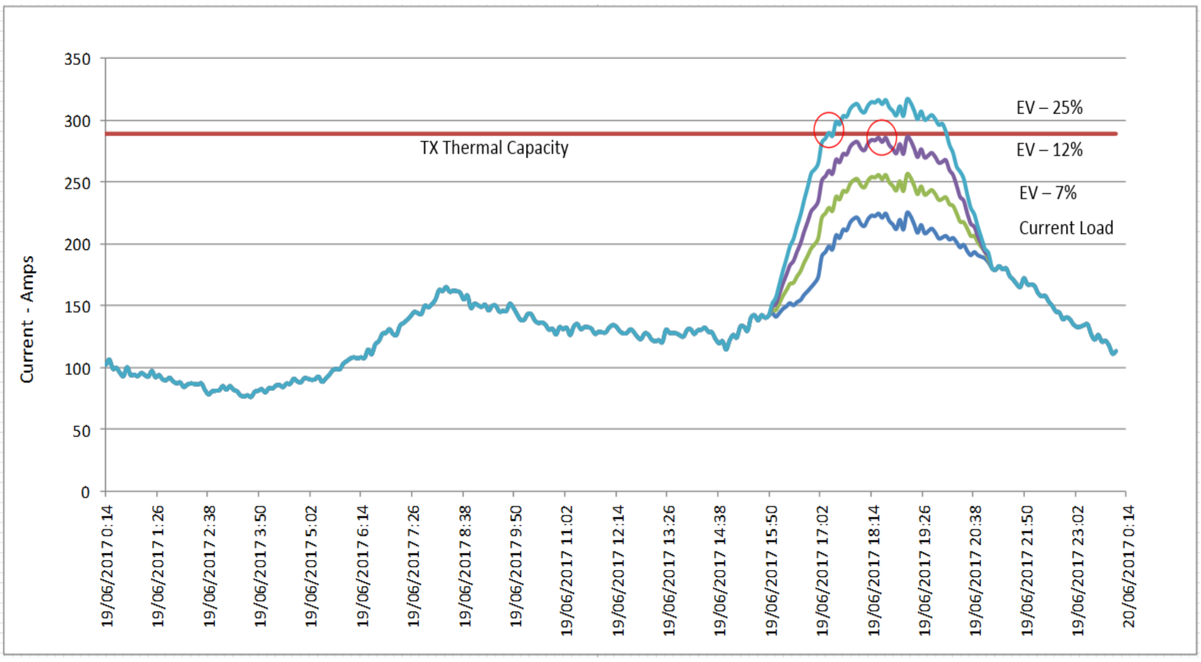

Figure 9-8 Distribution Transformer Load Profile by EV Penetration Rate

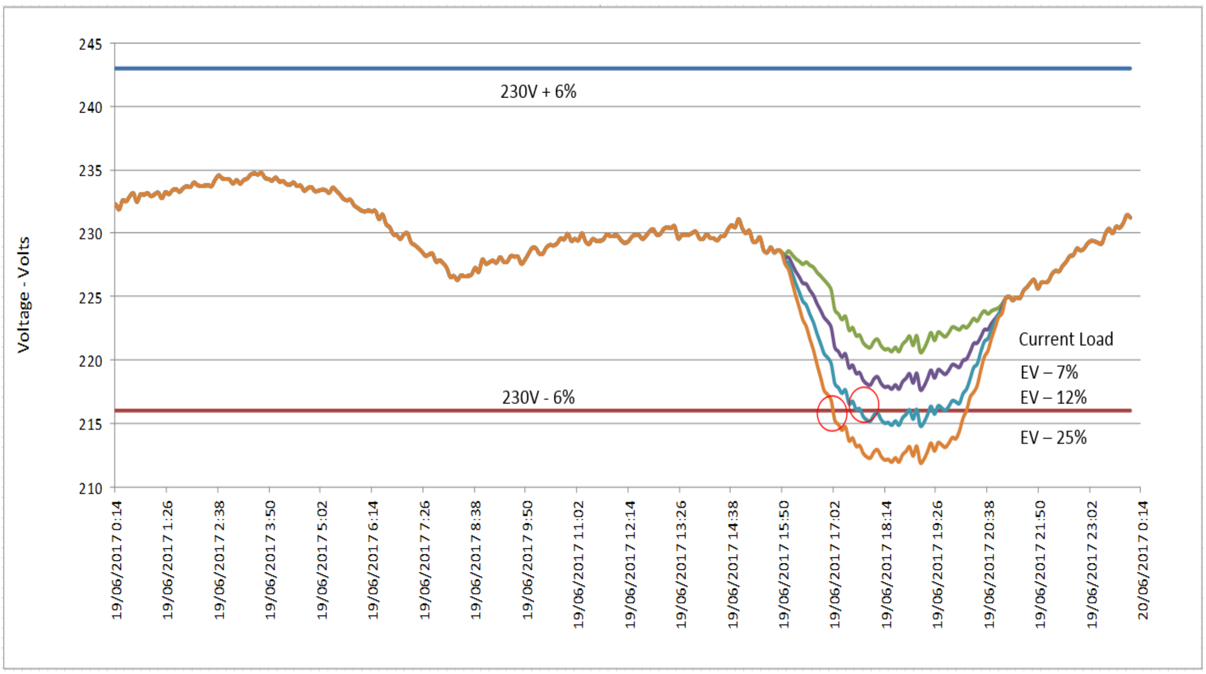

Figure 9-9 End of Line LV Voltage Profile by EV Penetration Rate

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. However, the time of use of these stations appears to raise off-peak demand and reduce the duration of the low demand period.

Figure 9-10 Public Electric Vehicle Charger (Upper Hutt)

Buses

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 involves working with one of the bus service providers in Wellington and study impact from adopting EV transportation to our network. 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.

Figure 9-11 Electric Bus using a Pantograph Fast Opportunity Charger on WELL network

Ferries

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 and engages new technologies to replace traditional solutions. Learnings from the bus projects will benefit this project.

9.4.3 Distributed Generation (DG)

Distributed generation (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. There are currently 1,156 PV installations connected to the WELL network with 3,859 kVA capacity and a predicted cumulative net injection of less than 200 kVA. While PV installations are the most common form of small-scale distributed generation they currently have minimal impact on the network and demand profile.

Figure 9-12 A Typical Rooftop PV Installation

- 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 62.85 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 9-13 shows projected PV capacities and impact of different levels of PV adoption and potential over-generation, combined with the load growth forecast over the same period. The PV peak output is not co-incident with network peak demand periods.

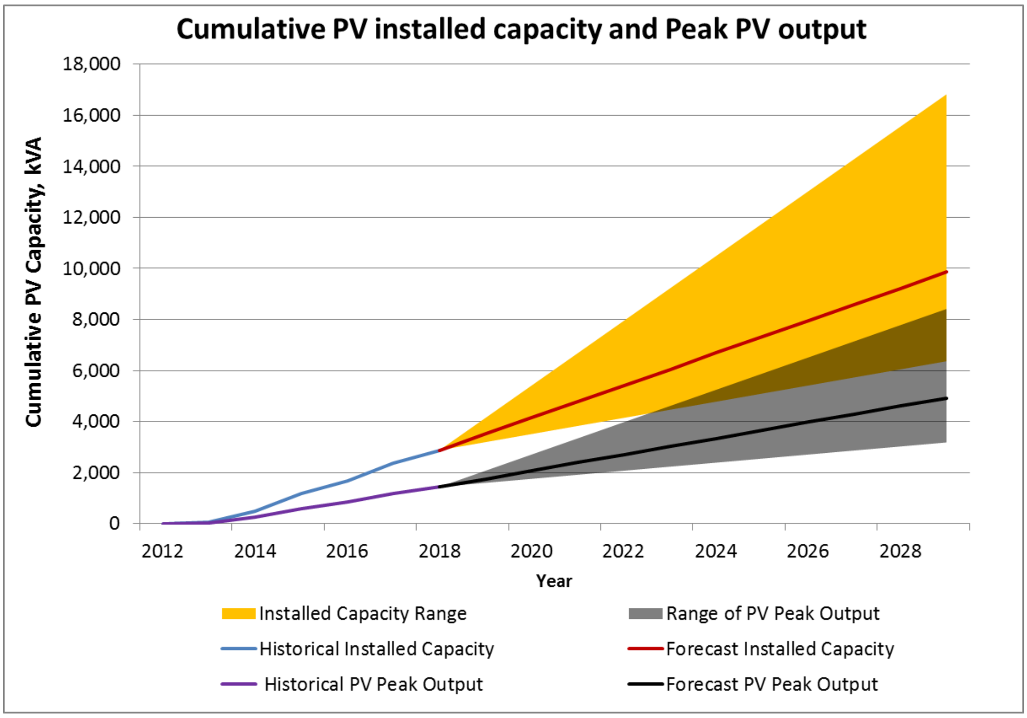

Figure 9-13 Projected PV Installed Capacity and Projected peak PV output

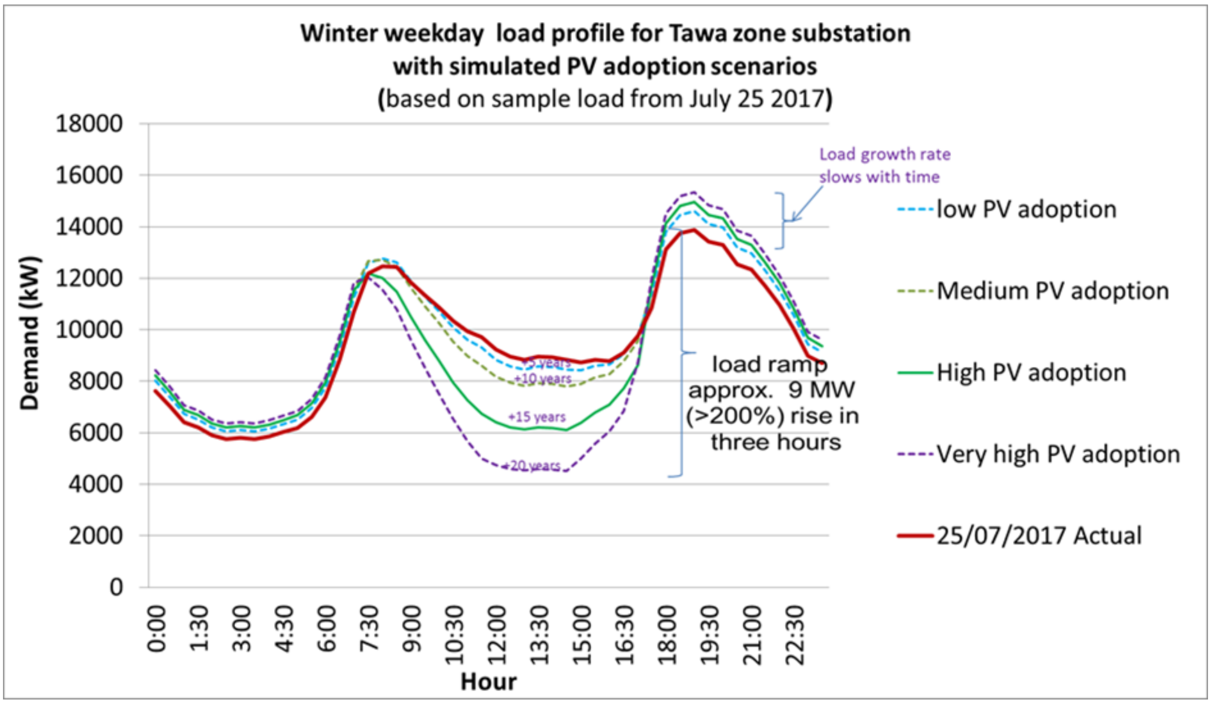

Figure 9-14 Impact of Different Levels of PV Adoption

Issues for WELL with regard to DG connections to the network include:

- New DG installations do not follow the required network connection standard and WELL does not have 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, WELL remains aware that with a higher penetration and area diversity this will happen if not studied and managed;
- Incorrect inverter protection settings cause ability to ride through faults during voltage or frequency excursion events, fault current contribution, islanding protection;
- Other impact from a higher DG installed capacity in the network are over voltages and may lead to more network congestions, with upstream equipment overloading due to excessive reverse power flow during high output – low demand period;
- To maximise the amount of DGs on the network, greater visibility on DG host capacity and control of the LV network is required and 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 will review the latest guideline in conjunction with the re-evaluation of current application process, update if appropriate[71];
- 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 activity on the DG market increases, it is expected that the demand profile may be distorted, and there may be a need to

[71] 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.

augment network capacity to accommodate power flows from distributed generation when it exceeds the local load and network capacity; and

- 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.

9.4.4 Energy Storage

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.

Batteries

WELL has partnered with Wellington City Council (WCC) and Contact Energy (Contact) to trial rooftop solar power systems coupled with battery storage. One initiative of the trial is investigating whether enabling customers to run a micro grid that is islanded from the network makes Wellington more resilient.

Contact and WELL can control the batteries and view the meter data captured. This data includes the solar output, battery state of charge and household usage. The batteries can be activated during a fault or peak demand periods to reduce loading on the network. Early results from the trial (still in progress) 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.

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.

Hot water

Residential and commercial hot water storage systems are forms of energy storage and can be controlled via our ripple 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 can serve as a local energy buffer (within its capacity limit) that alleviates some of the impact listed in the DG section. However, if not managed properly, storage can contribute to a higher peak and causing more issues.

Hydrogen

Another area that needs to be considered is the hydrogen application and the hydrogen fuel cell technology. This technology is still at the early development stage with very limited conceptual designs available. However, hydrogen solution offers some unique competitive advantages in comparison with electro-chemical based electricity storage like batteries. WELL's sister companies in Australia are currently doing trial projects that involves converting surplus electricity to hydrogen and this study will benefit WELL on future planning on alternative energy storage and dual fuel options.

9.4.5 Energy Efficiency

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 Energy Efficiency and Conservation Authority (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.

Figure 9-15 shows the Wellington network energy consumption trend. 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 on network efficiency with DER penetration, which is likely to reduce the overall technical loss as less volume of energy is transferred from the GXP; and
- Understand how appliances with better efficiency will assist in lowering energy use and reducing peak demand that will assist in peak loading control.

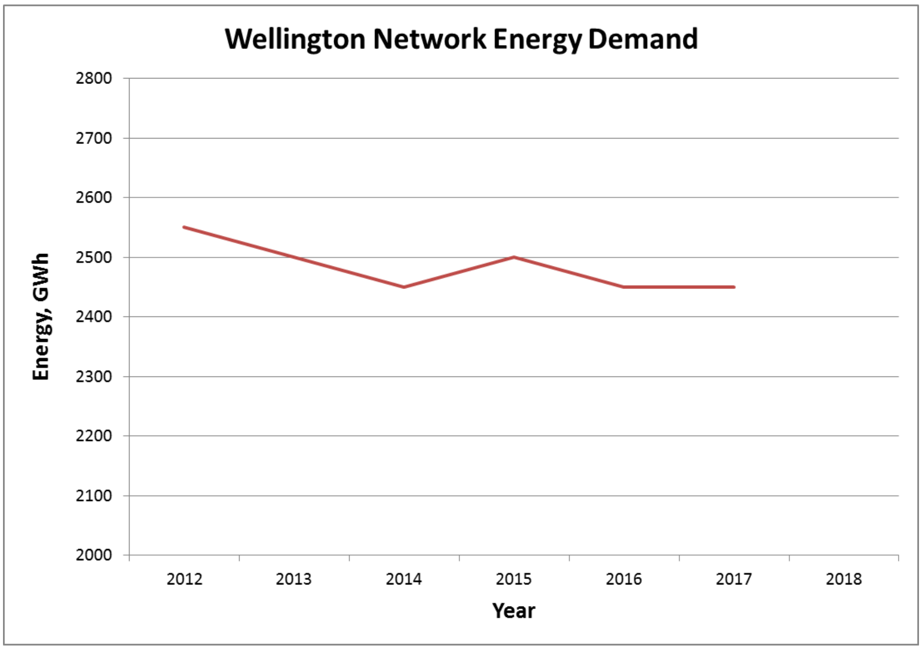

Figure 9-15 Wellington Network Energy Consumption

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[72];
- 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 the EV section.

The energy efficiency development plan will focus on processes and policies to encourage and support adoption of energy efficient equipment when developing assets as well as better operational practices.

9.4.6 Advanced Network

Advanced network, also known as smart network refers to a network made up of elements in the field and outside of the master station that:

(i) 'Are aware of themselves', i.e. can measure their operating parameters;

(ii) Can communicate these parameters (including the element physical attributes) with other network elements; and

(iii) Are controllable from local logic or from remote signals.

These elements will be required to develop a full DSO operating system.

Most of the investment in developing advanced networks will be on the LV circuits as traditionally, EDBs do not normally monitor LV status in real time in the same way as they do for sub-transmission and distribution. The benefits of monitoring LV have not justified the costs. The accepted industry practice on 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.[73]

Emerging technologies are also lowering the cost of LV monitoring with functions for monitoring power flows and power quality. Metering all individual connection points or even at all distribution transformers will be very costly to consumers, therefore it requires WELL to understand the critical network connection points, e.g. disruptors, and invest wisely to keep the balance between overall costs and data completeness. The new systems can offer real-time data access and/or ability to log the data locally or remotely for later download.

[72] https://wellington.govt.nz/~/media/your-council/meetings/committees/transport-and-urban–development-committee/2014/08/report8attachment1.pdf

[73] 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.

WELL continues to run trials to prove products that are getting available on the market for LV monitoring. Figure 9-16 and Figure 9-17 show data from the trial LV monitoring system trial available near-real-time and also logged at a remote server. Understanding the unique demand patterns on LV from different customers is critical for the network owners to develop an energy balance system and release spare capacities that are available for customer to use without paying for significant network upgrade costs.

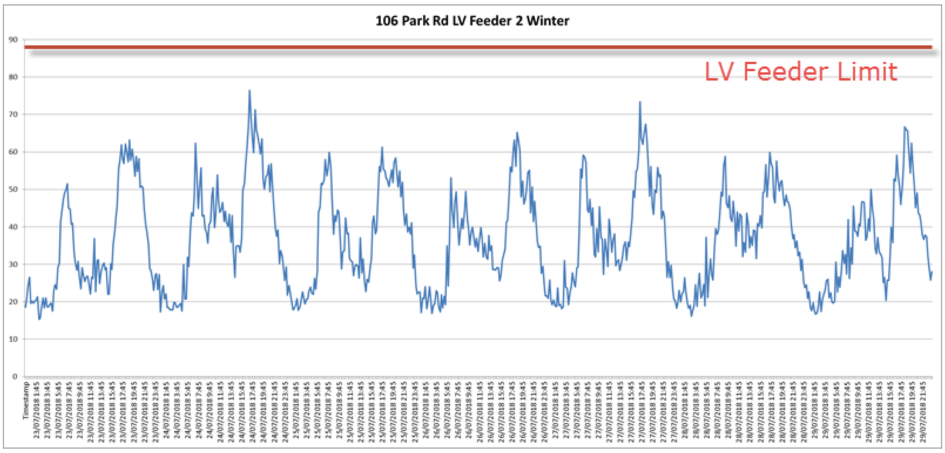

Figure 9-16 Typical Residential LV feeder load profile from WELL LV Trial Projects

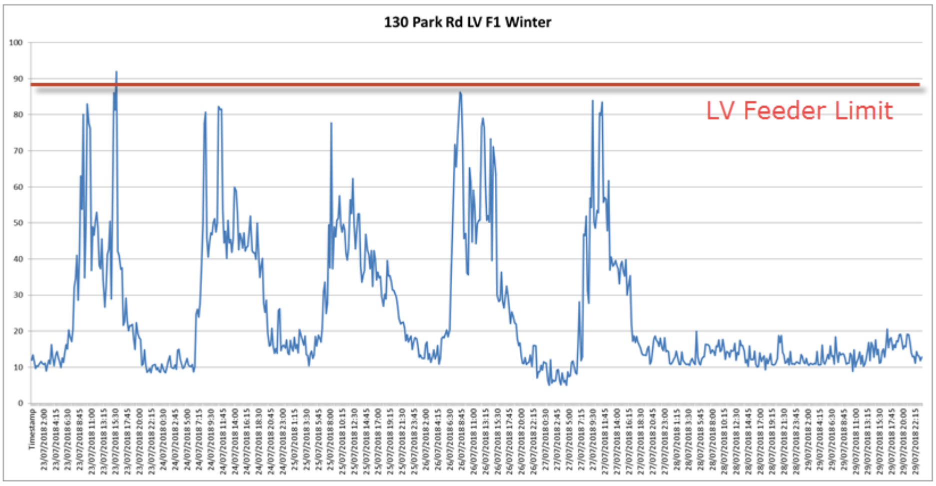

Figure 9-17 Typical Commercial LV feeder load profile from WELL LV Trial Projects

LV monitoring makes the daily asset loading patterns visible, enabling operations and planning to optimise asset utilisation as available asset loading information will not be limited to the peak loading. Full visibility requires free and unobstructed access to historical and lives metering data. Accuracy of registry information relating to ripple controlled devices 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 9-18 shows a concept for LV monitoring and control based on LV monitoring, dispatch and ripple control.

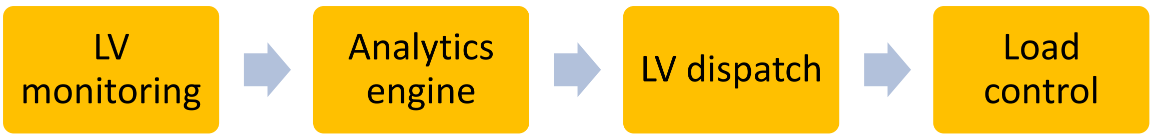

Figure 9-18 LV Network Control Concept

Advanced network elements are able to adjust local load and effect network reconfiguration in response to network conditions and need. This capability can be used to isolate faulted network sections or implement demand response. Building blocks for smart networks include:

- Distributed energy resources (DER);
- Enhanced smart meter functions. Future smart meters should provide opportunities for a variety of applications: ability to monitor real-time loading data, broken neutral (as a safety feature), load control, outage prediction, and dynamic pricing (revenue risk) 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 thus 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, and controls reach into zone substations. 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.

Opportunities for smart 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, lead to more complicated outage planning if using traditional outage planning approaches. By leveraging smart networks to create outage windows when needed and by controlling distributed generation and flexible loads, the complexity and risk of maintenance outages could be reduced; and
- AMI coupled with the “Internet of Things” (both IoT for consumer’s devices and IoT for industrial machines) provides a platform for automated load response to network conditions and may lead to a greater need for network resilience than 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 smart 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 development plan will include both primary and secondary assets. The initial effort will be in developing a knowledge base through small scale trials to evolve the network into a smarter network.

9.4.7 Master Station and Real-time Technology

Network real-time technology refers to secondary systems that enable a network operator to view the network from a central point and automate the 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 the real-time technology that is in a centralised location and providing interface to smart network (discussed in the previous chapter).

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.

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 complete detail of assets including the LV network. Asset location information from GIS used in combination with real-time system information from SCADA supports planning and a rapid response to outages. This has resulted in a more efficient work flow in day to day business operations.

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 distributed energy resource (DER) control;
- An integrated network model for design, planning, protection, reliability studies and operations;
- Standardization with majority of industry applications and easy integration with legacy and third party software; and

- Advanced analytics[74] to inform operators of the impact of load and generation scenarios ahead of real-time (such as system constraints), 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. This development plan outlines WELL strategies for network real-time technology and development of the necessary capability to transition to a DSO.

9.4.8 Digitisation and Data Transformation

Distributed energy resources and smart grids 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.

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 resources, and collection of network data to improve situational awareness and services. Current market developments include:

- Technology firms with internet based service offerings 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 retailers 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 around access to customer data from the smart meters and current capability to make use of the data;

- 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 (CIA).

[74] Advanced Analytics include: 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.

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 entry barriers for technology and other digitally savvy 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 utilities.

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, such as demand-response programs;

- 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.

WELL's current circumstance is that of having an asset base with a significant portion of legacy, digitally incapable assets and limited industry knowledge to learn from. The 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.

This Digitisation and Data Transformation Development Plan identifies IT technology required to support the processing capability and provide hardware that supports new software, application and storage development.

Under the current SCPP program WELL is building three new data centres to improve resiliency. Once the primary goal defined under the SCPP scope is achieved, it may be possible to use the established system to support the digitisation process, storage, interface with other cloud based system and data analytics.

9.5 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, concepts and solutions and their practical applications. 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 desire of providing the most efficient and cost effective energy cost options to consumers. The AMP over the next 2 – 3 years has a strong focus on R&D that gets WELL ready to meet future challenge and start the transformation journey.

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 learnings and learn from others.

Figure 9-19 shows the spread of investments over the next ten years required to assess the impact of emerging technologies and to develop capabilities WELL needs to transform into a DSO.

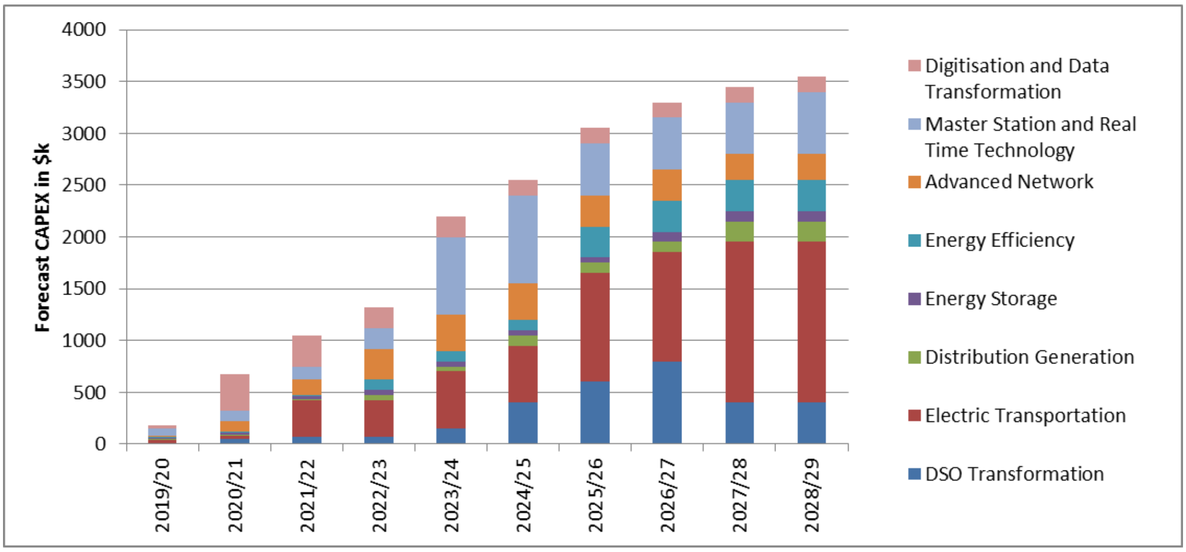

Figure 9-19 Spread of Investment in Emerging Technologies

The total capital expenditure forecast for the emerging technology related development plan over the next 10 years is shown in Table 9-2 and Table 9-3.

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
DSO Transformation	10	50	70	70	150	400	600	800	400	400
Electric Transportation	30	30	350	350	550	550	1,050	1,050	1,550	1,550
Distribution Generation	5	10	10	50	50	100	100	100	200	200
Energy Storage	10	20	30	50	50	50	50	100	100	100
Energy Efficiency	10	10	10	100	100	100	300	300	300	300
Advanced Network	20	100	150	300	350	350	300	300	250	250
Master Station and Real Time Technology	70	100	130	200	750	850	500	500	500	600
Digitisation and Data Transformation	30	350	300	200	200	150	150	150	150	150
Capital Expenditure Total	**185**	**670**	**1,050**	**1,320**	**2,200**	**2,550**	**3,050**	**3,300**	**3,450**	**3,550**

Table 9-2 CAPEX Forecast Summary (Emerging Technologies Development Plans) ($K in constant prices)

Expenditure Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
DSO Transformation	50	200	350	300	340	320	440	420	440	420
Electric Transportation	25	55	65	80	80	80	50	60	60	60
Distribution Generation	30	60	20	30	40	80	40	50	40	80
Energy Storage	30	90	110	60	25	25	25	25	25	25
Energy Efficiency	20	40	40	10	10	10	10	10	10	10
Advanced Network	15	70	80	80	70	50	50	50	50	50
Master Station and Real Time Technology	10	10	30	100	50	50	50	50	50	50
Digitisation and Data Transformation	30	80	80	30	30	30	30	30	30	30
Operational Expenditure Total	**210**	**605**	**775**	**690**	**645**	**645**	**695**	**695**	**705**	**725**

Table 9-3 OPEX 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 consumers. 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 in the repositories and what the data is used for. Areas where asset data is incomplete are identified and initiatives to improve the quality of this data are discussed.

Table 10-1 shows where asset information is stored within WELL's systems.

	Physical Assets	Equipment Ratings	Asset Condition	Connectivity	Customer Service	Financial Management
SCADA / PoF		✓		✓	✓	
GIS	✓	✓		✓	✓	
Project Wise	✓	✓			✓	
Power Factory		✓		✓		
Station Ware	✓	✓				
SAP PM	✓		✓		✓	
GenTrack				✓	✓	
SAP (Financial)						✓

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 to assist real time operational management of the WELL network. The SCADA system provides operation, monitoring and control of the network at 11 kV and above. Low voltage (400 volts or below) outage reports are recorded by the GE PowerOn Fusion Calltaker system utilised by the Outage Manager at the WELL Contact Centre. The Calltaker system electronically interfaces with the Field Service Provider's dispatch system to dispatch field staff for fault response.

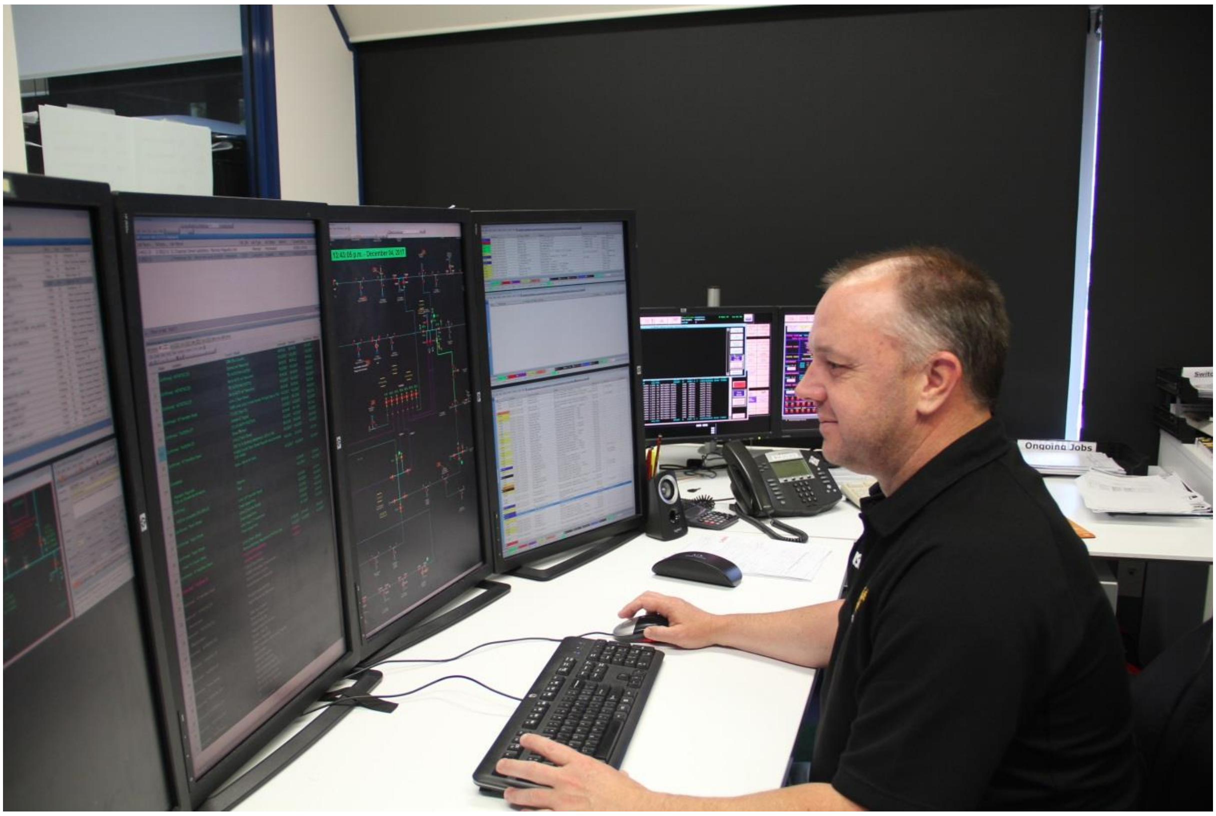

Figure 10-1 Main Network Control Room

WELL is planning to develop additional functions to further enhance the PowerOn Fusion platform, as well as investigating development options for offline operator nodes to improve system resiliency and cyber security.

WELL is also currently investigating upgrade options for two other systems related to the SCADA:

- WELL currently uses TrendSCADA, 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 electricity distribution companies and which may offer greater benefits to the business and improve user-friendliness; and

- 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. Replacement options being investigated include an integrated part of the GE PowerOn Fusion system or a standalone package.

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 links to WELL's maintenance management system (SAP PM), GenTrack and the Field Service Provider's systems to ensure it is updated with the latest asset data and asset condition information. Asset information is updated nightly between the systems.

GIS provides a useful tool for engineering decision by making it easy to:

- Analyse asset population; and
- Carry out geospatial analysis of connectivity, SAP PM defects, maintenance and test history, and asset performance.

A project is underway to replace the existing GIS with a newer version which provides better system performance, data accuracy and improved functionality.

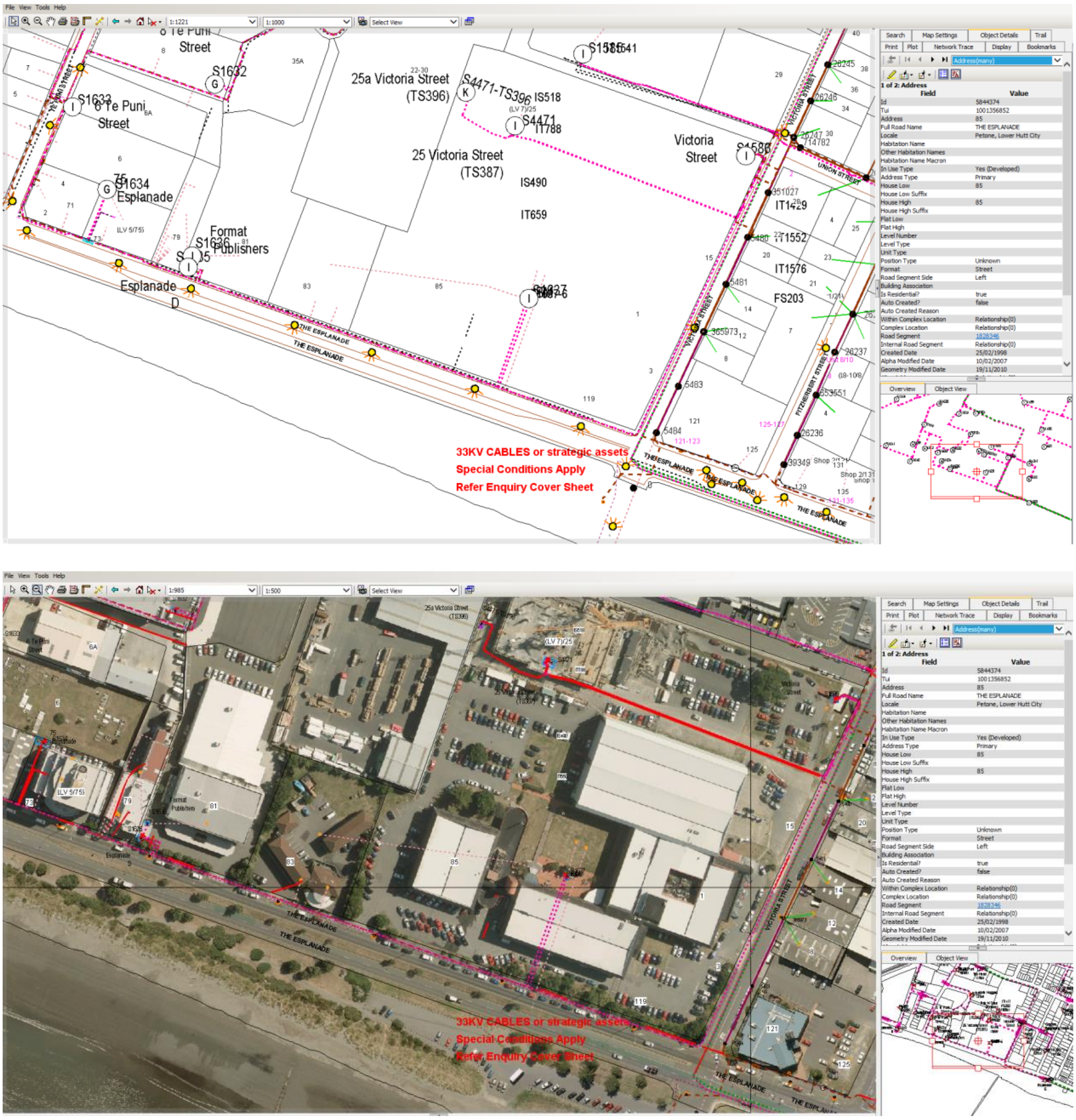

Figure 10-2 Screen Shot of Smallworld GIS system

The existing GIS currently includes SIAS, a web based GIS viewer that is available for staff and external contractors. WELL plan to upgrade SIAS within the next five years with a newer GE GIS platform to provide additional web based GIS functionality.

10.1.1.3 ProjectWise

WELL stores all Grid exit point, substation, system drawings, and historic asset information diagrams in ProjectWise in PDF and CAD format.

10.1.1.4 DIgSILENT Power Factory

The DigSILENT Power Factory is used to model and simulate the electrical distribution network and analyse load flows for development planning, contingency planning, reliability and protection studies. The Power Factory database contains detailed connectivity and asset rating information. To ensure ongoing accuracy, the model is manually updated every quarter to include recently commissioned network assets and augmentations. Model updates are regularly distributed to design consultants to ensure consistency for commissioned studies.

10.1.1.5 Cymcap

CYMCAP (cable ampacity and simulation tool) is used to model the ratings of underground cables at all voltages for existing cables in service and new developments.

10.1.1.6 LVDrop

LV Drop is used to model low voltage electrical networks to ascertain voltage drops and loading of conductors and transformers. LV Drop contains all the relevant LV cable, conductor, transformer and ADMD information and ratings. It is used for new subdivision reticulation designs and forms part of the customer connections and planning process.

WELL plans to upgrade LVDrop to the latest version in 2019.

10.1.1.7 DIgSILENT Station Ware

DigSILENT Station Ware is a centralised protection setting database and device management tool. It holds relay and device information, parameters and settings files. Station Ware is accessible remotely, via the Citrix environment, to allow input and modification by approved design consultants. Protection settings are uploaded to the Station Ware database for review and approval. The settings are then distributed to commissioning personnel for application in the field.

WELL has updated the relay database to include the latest relay setting templates in 2018.

10.1.1.8 SAP PM Asset Management System

WELL uses the SAP Plant Maintenance (SAP PM) to plan its maintenance activities and capture asset condition data for both preventative and corrective works. This system allows WELL to issue maintenance workpacks to service providers electronically. Maintenance results are returned electronically via a web interface. Asset data is synchronised with GIS, which allows maintenance tasks to be grouped spatially to increase efficiency.

10.1.2 GenTrack

GenTrack is used to manage ICP and revenue data, and deliver billing and connection services. GenTrack is populated and synchronised with the central ICP registry. It interfaces with the GIS and PowerOn Fusion systems to provide visibility of consumers affected by planned and unplanned network outages. GenTrack also interfaces with the SAP financial system for billing.

10.1.3 SAP 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.

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 then updated when new needs are identified within the business or through changing regulatory requirements.

Asset management data requirements and processes are also specified in the Field Service Agreement with Northpower who input/manage the asset information in the SAP PM information system.

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 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 in systems such as Station Ware and transferred to the GIS during nightly updates between the systems.

Processes are in place to establish one 'source-of-truth' for each category of information and synchronisation of data between the various information systems.

To ensure data quality, 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 being reviewed to fill in gaps
	Condition Assessment (CA) scores incorrect for early inspections arising from misunderstandings of new Field Inspectors	Standardised CA scoring and field training is in place Annual re-inspection will provide correct information from second pass
Power Factory	Historical network augmentations or customer connections may not be captured in the model	Network 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
Station Ware	Not all station protection relay settings have been captured in Station Ware	Settings are updated at the time of projects being undertaken, or audited as required to undertake protection and network studies. Settings are intended to be updated following relay testing where the technician can enter as-left settings following the testing
PowerOn Fusion v5.2	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

10.4 Information Systems Plan

WELL assesses its network support information systems to ensure the software and supporting hardware is supported and continues to provide WELL's 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 for core version 4.0 to 4.3 (2019)	Allows future upgrade to 5.0 Allows GIS platform to be installed for deployment of Network Viewer.	300
	SIAS upgrade to Network Viewer (2019)	Allows better web based functionality, and can be directly read by the B4UDig automated plan release system.	650
PowerOn Fusion v5.2	Upgrade Stage 2 (2019)	Functional enhancements to improve the user experience, geographical data and OMS tools	500
PowerOn Advantage V6.X	New ADMS Platform (2021/2022)	Existing version will be no longer supported by the Vendor, new platform with functional enhancements, user experience and third party software interface	1500
Load Control Master Station	Replacement Foxboro Master Station (2019)	Replacement of legacy master station, improve functionality and enable modern platform interface	710
Power Factory DigSILENT	Version 2018 (2019)	Additional licence, improve functionality, user experience and system stability	85
LV Drop	Version 8.X	Improve functionality and model accuracy	45

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.

10.7 Non-Network Asset Expenditure Forecast

Routine Expenditure	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Software and Licenses	1,342	1,096	1,237	1,210	1,188	1,039	1,028	1,018	1,018	1,018
IT Infrastructure	419	404	436	430	420	409	402	394	394	394
Streamlined CPP	3,130	1,950	-	-	-	-	-	-	-	-
Total Non-network CAPEX	**4,891**	**3,450**	**1,673**	**1,640**	**1,608**	**1,448**	**1,430**	**1,412**	**1,412**	**1,412**
System Operations and Network Support	5,769	5,795	5,795	5,795	5,795	5,795	5,795	5,795	5,795	5,795
Business Support	11,747	11,780	11,420	11,420	11,420	11,420	11,420	11,420	11,420	11,420
Total Non-network OPEX	**17,516**	**17,575**	**17,215**	**17,215**	**17,215**	**17,215**	**17,215**	**17,215**	**17,215**	**17,215**

Table 10-4 Non-Network Expenditure Forecast
($K in constant prices)

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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. WELL's approach for providing consumers with a safe, reliable and cost effective electricity supply under normal circumstances was described in Section 6. Changes due to growing demand from increased population or industry is covered by the Network Development Plan in Section 8.

As a lifeline utility in accordance with the 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 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's SCPP application to address earthquake readiness following the 2016 Kaikoura earthquake (approved by the Commission in March 2018). Aside from the resilience improvements associated with WELL's SCPP application, an additional positive outcome for Wellington consumers was that, due to a reduction from Transpower's pass through balance, prices remained flat.

WELL has investigated future resilience initiatives to improve the networks ability to withstand High Impact Low Probability (HILP) events but these would need extensive consultation with consumers in the Wellington region prior to implementation as prices will be likely to increase if these plans were to go ahead.

The WELL resilience framework has been sectionalised in this plan as 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.

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. 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 that is 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. The sea level globally was rising at an average of 1.7mm per year throughout the 20th century, however this has been increasing with an average of 3.3mm rise per year since 1993. These levels are global averages and the local rise may differ.

Rising sea levels present a risk in central Wellington where a large number of substations in the CBD are in the basements of buildings, while more turbulent winds and the potential for more rainfall increases the risks of land slips and vegetation damaging network equipment.

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 into 2019 WeLG has been conducting another project on regional disaster response. A key component of this project has been consideration of the interdependencies between lifeline utilities and how these are likely to affect the restoration process. This project has involved detailed modelling of the likely damage to each lifeline utility network based on GNS modelling of the Wellington fault and regional geography.

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 CDEMA Act 2016. It provides information for the initiation of measures for saving life, relieving distress and restoring electricity supply.

This CDEMA 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 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.

11.3.4.10 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 are undertaken on behalf of WELL by GNS and other external providers.

11.4.2 Strategies to Mitigate the Impact of HILP Events

11.4.2.1 Specific 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.

11.4.2.2 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, 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.

Figure 11-1 Storm Damage - June 2013

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.

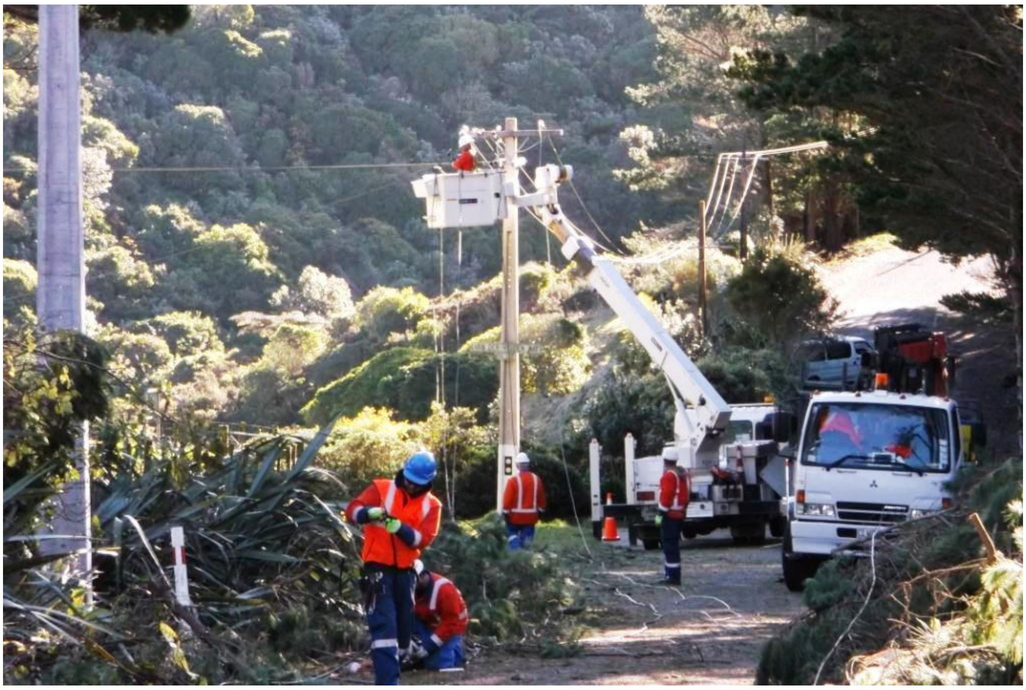

Figure 11-2 Contractors Working to Repair Storm Damaged Lines - June 2013

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.

11.4.2.3 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 sub transmission 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 sub transmission 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, Mana-Plimmerton and north of Upper Hutt being the most obvious examples. 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.

11.4.2.4 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 48,000 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 St, 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 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 300-400 m 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 11-3 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.

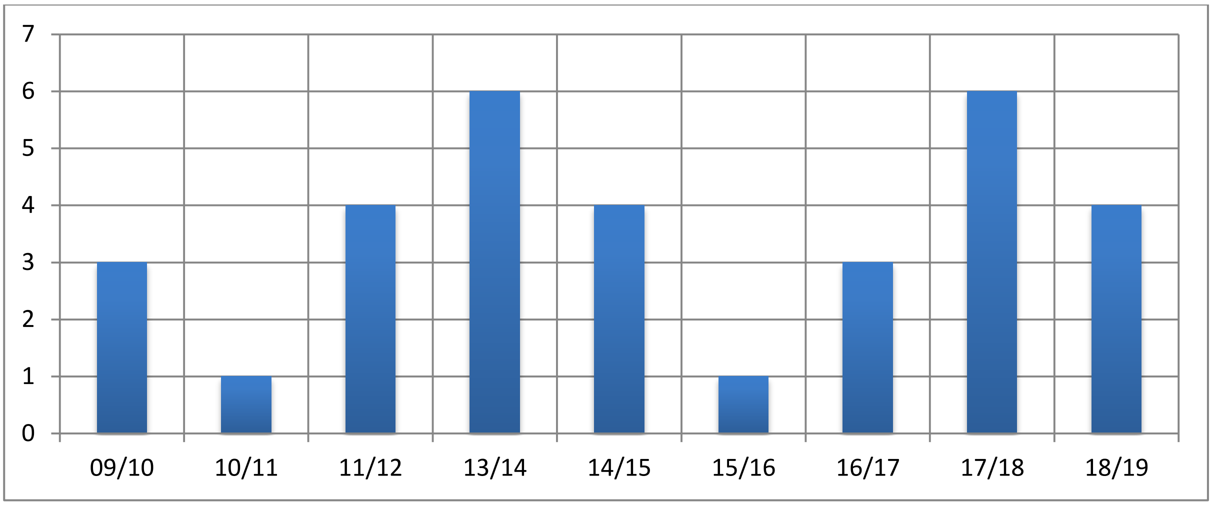

Figure 11-4 Number of Upstream Supply Failure Outages Experienced by WELL per Regulatory Y ear

11.4.2.5 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 below in a map of the region created by GNS science which looked to increase knowledge of the earthquake risk in the Wellington region.

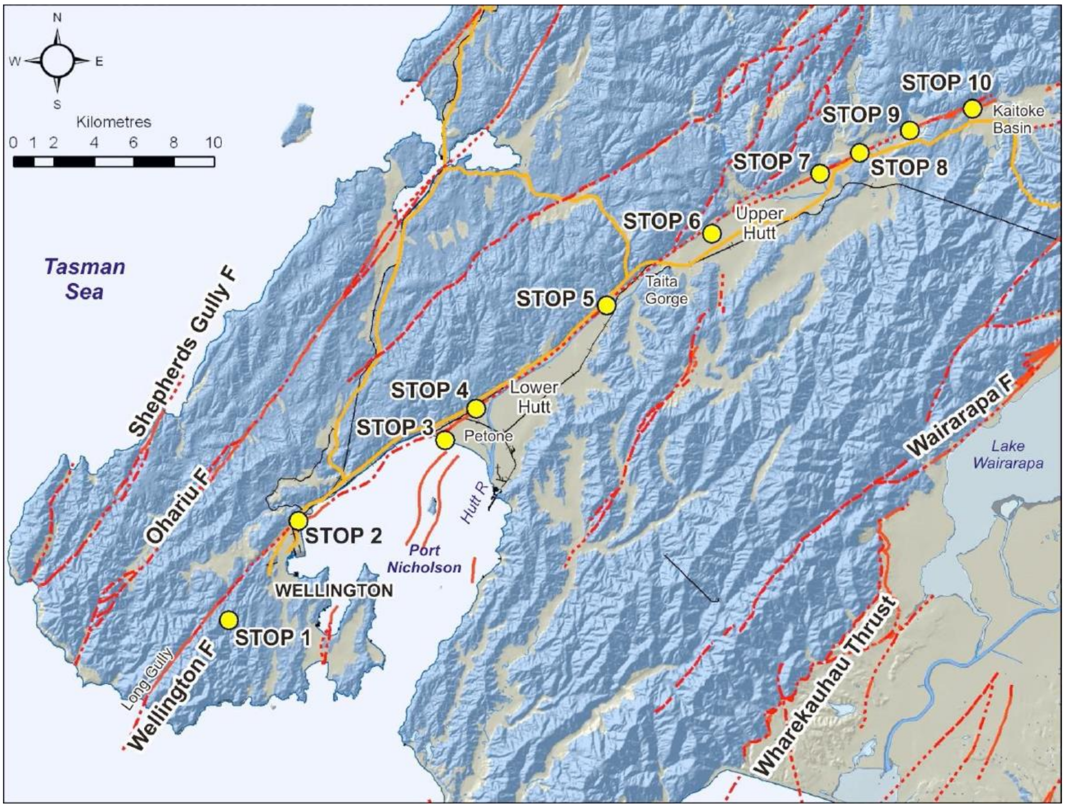

Figure 11-5 Wellington Region Fault Lines[75]

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.

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, 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, the Commission approved WELL's SCPP to enable $31.24 million of additional spending targeted at improving the response following a major earthquake in the region. This SCPP was applied for

[75] 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).

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. Aside from the resilience improvements associated with WELL's SCPP application, an additional positive outcome for Wellington consumers was that, due to a reduction from Transpower's pass through balance, prices remained flat. 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[76] report of 2013.

Road damage following a major earthquake could lead to the WELL network area being broken into 5 transport 'islands' with road access between areas not possible. These transport 'islands' and the predicted timeframes before transport links are opened are shown below (Figure 11-7).

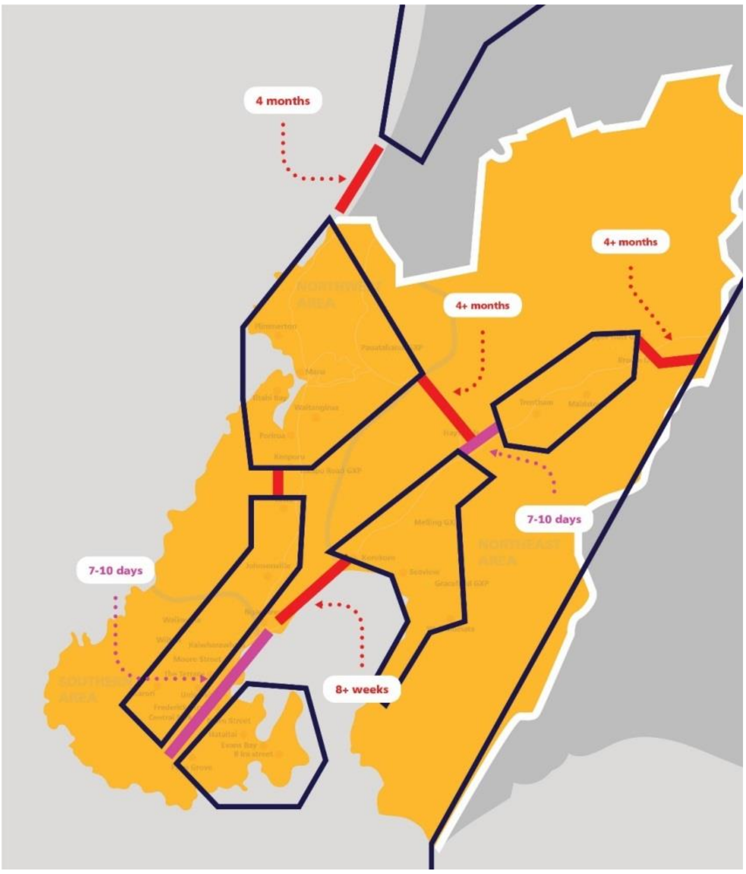

Figure 11-7 Affected Transport Links After a Major Earthquake

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
3. Mobile Substations
4. Radio and Phones
5. Seismic Reinforcement

[76] "Restoring Wellington's transport links after a major earthquake" Wellington Lifelines Group, March 2013.

11.5.2.1 Spares

The spares workstream has been further split into three projects with overhead line spares, cable and joint spares and the mobile switchboard. The spares workstream also includes the setup of stores locations throughout the network.

Once purchased, cable and joint spares are stored throughout the region to enable repair of the 11kV cable network to begin without waiting for transport routes to open.

Figure 11-8 Repair Equipment Stored at Todd Park (left) and Palm Grove (right)

At the time of publishing the total spares workstream is 52% complete. All underground spares have been purchased and storage sites made ready for arrival of the remaining overhead line spares. This workstream is expected to be complete by the end of 2019.

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.

A high level scope of work for the construction of these data centres has been completed and approved in September 2018. Work is now underway on the solution architecture and detailed scope. 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, switchgear and control/communications each separately transportable. The transformer will be mounted on a trailer with the other two modules fitting the dimensions of a standard 20ft shipping container. The decision to construct the substation in this manner, rather than on a trailer as is more common, was made due to transport considerations. With road access being potentially affected, a smaller trailer and two containers 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.

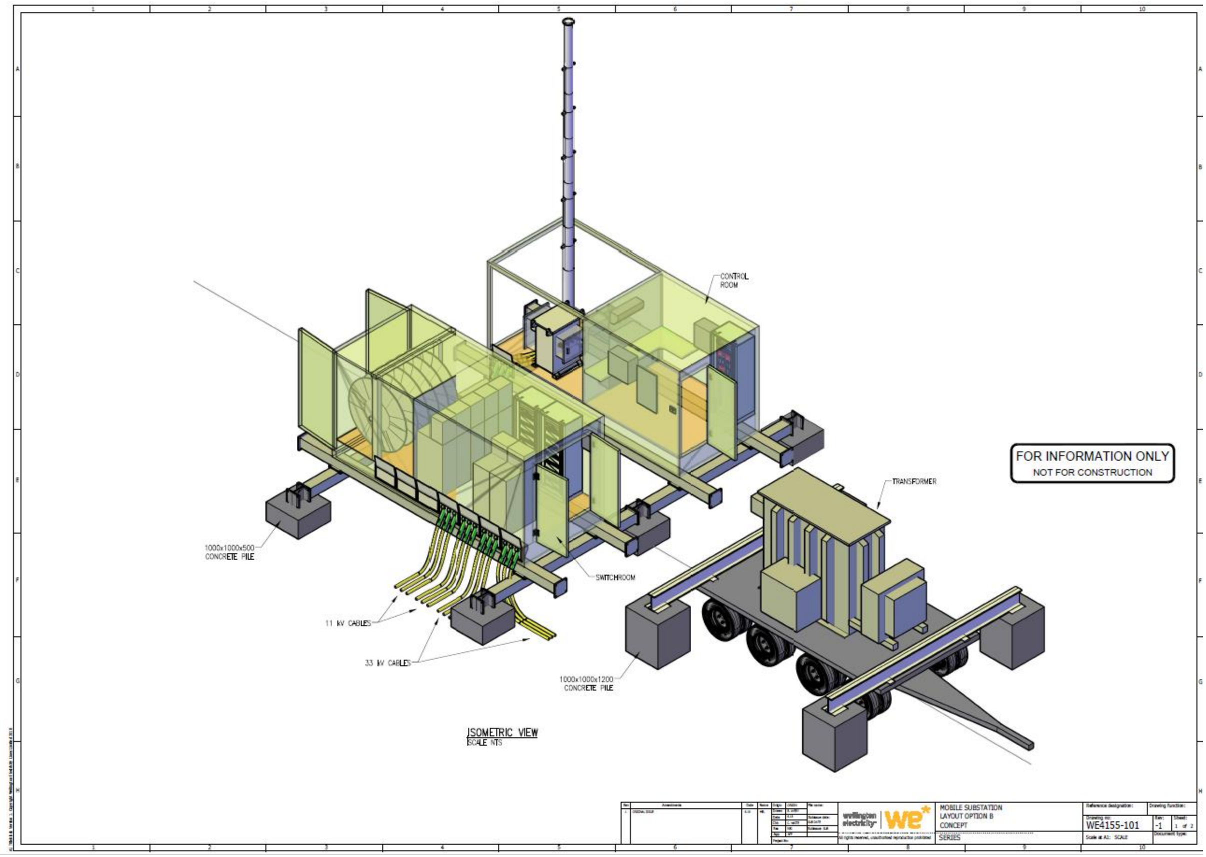

Figure 11-8 Concept Layout of Mobile Substation

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 are likely to be damaged in an earthquake. Service providers for this work have been appointed and will shortly commence work.

The telephone workstream will provide 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 will have a robust configuration to ensure continued operation in a disaster scenario, when public communications networks may be compromised. Hardware suppliers and service providers for this work have been appointed and the build of this system is underway.

These workstreams are progressing on schedule and are expected to be completed by the end of 2019.

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 30 buildings have been successfully strengthened. The strengthening programme is expected to run until the end of January 2020.

Figure 11-9 Seismic Bracing Installed inside Frederick St Zone Substation

11.5.3 Expenditure Summary

A summary of the expenditure associated with the earthquake readiness SCPP is shown in Table 11-1.

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

The SCPP programme is continuing with all work streams underway and on track to be delivered in accordance with the required schedule.

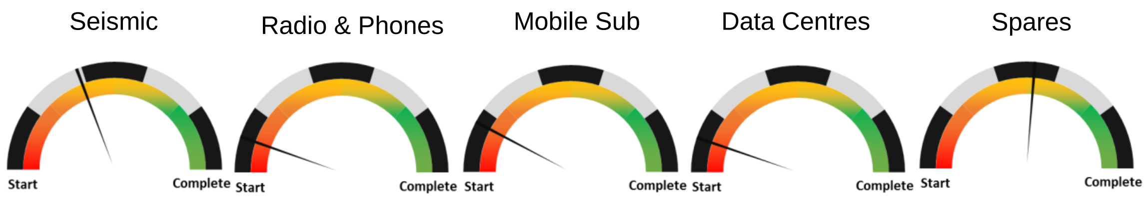

Figure 11-10 SCPP Progress by Work Stream

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	3,730	-	-	-	-	-	-	-	-	-
Zone Substations	2,360	1,710	-	-	-	-	-	-	-	-
Distribution Poles and Lines	-	-	-	-	-	-	-	-	-	-
Distribution Cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations	6,762	-	-	-	-	-	-	-	-	-
Distribution Switchgear	260	-	-	-	-	-	-	-	-	-
Other Network Assets	-	-	-	-	-	-	-	-	-	-
Total (Network)	**13,112**	**1,710**	-	-	-	-	-	-	-	-
Non Network Assets	3,130	1,950	-	-	-	-	-	-	-	-
Total	**16,242**	**3,660**	-	-	-	-	-	-	-	-

Table 11-2 SCPP Expenditure Forecast
($K in constant prices)

11.6 Future Resilience Work

Analysis completed as part of the SCPP application identified areas where resilience needs to be addressed but fall outside the scope of the readiness SCPP, these are:

- Central Park as a potential single point of failure; and
- The vulnerability of the sub transmission fluid-filled cables.

Solutions to these issues form part of the preferred options in the recently released Wellington Lifelines Group Regional Resilience Project Programme Business Case (WeLG RRP PBC)

The options that provide the most resilience benefit are often more costly than a like for like replacement and would require significant customer consultation due to the likely significant effect on pricing. WELL's intention is to continue to analyse these events in conjunction with WeLG and other lifeline utilities.

11.6.1 Central Park

There is a significant risk posed by a potential loss of supply to Central Park GXP. A longlisting exercise was 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. These options require consultation with Transpower.

This option will be 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.

The preferred option is shown in Figure 11-11 and sensitivities are shown in Figure 11-12.

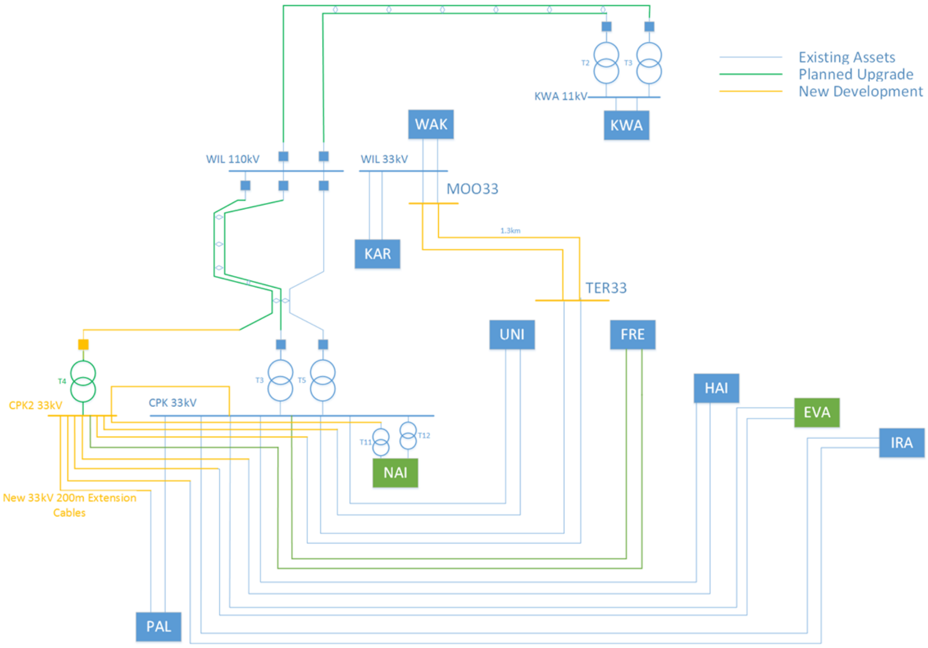

Figure 11-11 WELL's Proposed Mitigation for the Central Park Resilience Risk

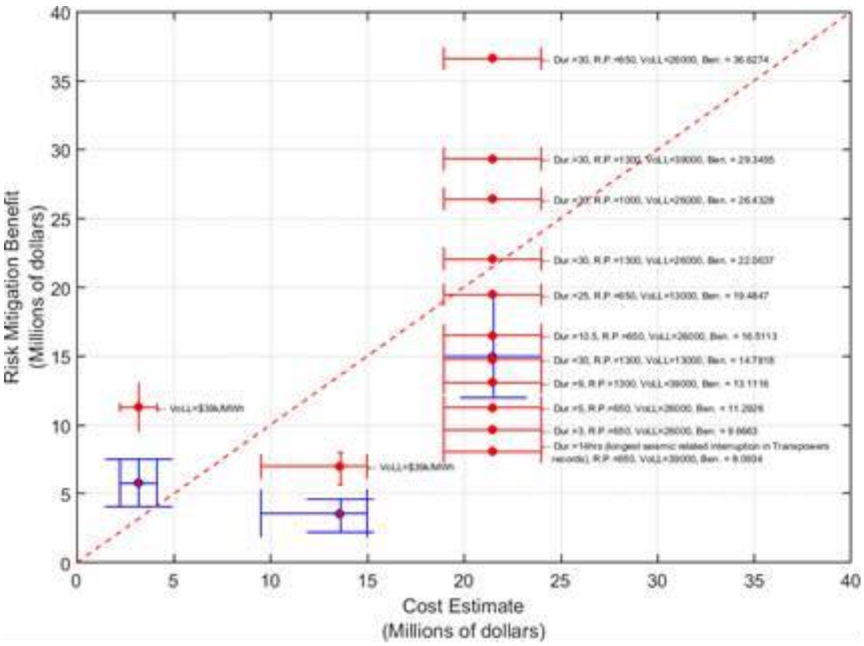

Figure 11-11 Transpower's Cost Benefit Analysis on Various CPK2 Options (in accordance with Grid Reliability Standard)

11.6.2 Sub transmission Fluid Filled Cables

The majority of the sub transmission 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 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 indicated in Section 7.

A significant earthquake can also 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 are limited 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 needs to be carried out. This is time consuming and requires a specialised skill set not available through local contractors. 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 has 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 3 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 sub-transmission 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 33kV 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.

The estimated cost of this future resilience work is set out in Table 11-3.

Future Resilience Work	Purpose	Cost	Note
Central Park 2 substation	Single point of failure	$40m	Initial estimates from options development with Transpower
Sub transmission cable	Radial subtransmission network with cables sharing routes	$160m	Construction of sub-transmission rings in Lower Hutt and Wellington

Table 11-3 Cost of Future Resilience Projects

These two future resilience works 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. As discussed in Section 7, WELL has a mature network of 11kV cables with some sections approaching their end of life and thus becoming more prone to earthquake damage. While the items planned for purchase as part of this 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.

Section 12

Expenditure Summary

12 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.

12.1 Capital Expenditure 2019-2029

12.1.1 Consumer Connections

The total forecast consumer connection capital expenditure for 2019 to 2029, as discussed in Section 8, is presented in Table 12-1.

Consumer Type	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Substation	4,289	4,356	4,356	4,708	4,732	4,756	4,779	4,803	4,827	4,827
Subdivision	2,379	2,496	3,475	4,087	4,100	4,044	4,125	4,208	4,292	4,378
High Voltage Connection	133	136	139	141	144	147	150	153	156	156
Residential Customers	1,127	1,154	1,170	1,198	1,215	1,244	1,262	1,292	1,310	1,310
Public Lighting	100	100	100	100	100	100	100	100	100	100
Total	**8,028**	**8,242**	**9,240**	**10,234**	**10,291**	**10,291**	**10,416**	**10,556**	**10,685**	**10,771**

Table 12-1 Consumer Connection Capital Expenditure Forecast
($K in constant prices)

12.1.2 System Growth

The total forecast capital expenditure for system growth and security of supply for 2019 to 2029, as discussed in Section 8, is presented in Table 12-2.

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	2,800	3,100	2,200	-	-	700	-	-	-	-
Zone Substations	1,400	1,760	1,900	3,200	2,600	-	-	1,300	1,700	-
Distribution Poles and Lines	-	-	-	-	-	-	-	-	-	-
Distribution Cables	1,000	600	2,000	2,600	4,100	2,800	2,000	1,800	1,500	1,500
Distribution Substations	-	-	-	-	-	-	-	-	-	-
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets[77]	800	-	-	-	-	-	-	-	-	-
Total	**6,000**	**5,460**	**6,100**	**5,800**	**6,700**	**3,500**	**2,000**	**3,100**	**3,200**	**1,500**

Table 12-2 System Growth Capital Expenditure Forecast ($K in constant prices)

[77] Other Network Assets includes the capital expenditure required for emerging technologies.

12.1.3 Asset Replacement and Renewal

The total forecast capital expenditure for asset replacement and renewal for 2019 to 2029 as discussed in Section 7 is presented in Table 12-3. This includes provision for replacements that arise from condition assessment programmes during the year.

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	350	350	350	350	350	3,350	2,850	1,850	1,850	350
Zone Substations	3,250	2,550	1,550	2,300	300	300	300	300	300	300
Distribution Poles and Lines	8,050	8,155	8,260	8,765	9,171	9,575	10,811	10,841	10,873	10,905
Distribution Cables	300	950	750	1,950	1,000	1,750	1,750	3,250	3,250	5,250
Distribution Substations	2,100	1,850	2,213	2,311	3,500	3,500	3,500	3,500	3,500	3,500
Distribution Switchgear	3,178	3,091	3,450	1,835	3,350	3,850	3,850	3,850	3,850	3,850
Other Network Assets	1,983	3,126	3,660	3,205	2,905	2,505	2,605	2,165	1,884	1,705
Total	**19,211**	**20,072**	**20,233**	**20,716**	**20,576**	**24,830**	**25,666**	**25,756**	**25,507**	**25,860**

Table 12-3 System Asset Replacement and Renewal Capital Expenditure Forecast ($K in constant prices)

12.1.4 Asset Relocations

The forecast asset relocation capital expenditure, primarily related to roading projects, is presented in Table 12-4.

Programme	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Roading Relocations	2,450	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029
Total	**2,450**	**1,783**	**1,801**	**1,819**	**1,837**	**1,874**	**1,912**	**1,950**	**1,989**	**2,029**

Table 12-4 Asset Relocation Capital Expenditure Forecast ($K in constant prices)

12.1.5 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 12-5.

Programme	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Worst Performing Feeders	1,571	2,107	1,592	1,717	1,413	1,413	1,455	1,499	1,544	1,590
Total Quality of Supply	**1,571**	**2,107**	**1,592**	**1,717**	**1,413**	**1,413**	**1,455**	**1,499**	**1,544**	**1,590**
Seismic Programme (BAU)	2,770	470	500	500	650	-	-	-	-	-
Streamlined CPP	13,112	1,710	-	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	**15,882**	**2,180**	**500**	**500**	**650**	**-**	**-**	**-**	**-**	**-**

Figure 12-5 Reliability, Safety and Environmental Capital Expenditure
($K in constant prices)

12.1.6 Non-network Assets

The forecast capital expenditure for non-network assets is presented in Table 12-6.

Routine Expenditure	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Software and Licenses	1,342	1,096	1,237	1,210	1,188	1,039	1,028	1,018	1,018	1,018
IT Infrastructure	419	404	436	430	420	409	402	394	394	394
Streamlined CPP	3,130	1,950	-	-	-	-	-	-	-	-
Total Non-network Assets	**4,891**	**3,450**	**1,673**	**1,640**	**1,608**	**1,448**	**1,430**	**1,412**	**1,412**	**1,412**

Table 12-6 Non-Network Asset Capital Expenditure Forecast
($K in constant prices)

12.1.7 Capital Expenditure Summary

Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Consumer Connection	8,028	8,242	9,240	10,234	10,291	10,291	10,416	10,556	10,685	10,771
System Growth	6,185	6,130	7,150	7,120	8,900	6,050	5,050	6,400	6,650	5,050
Asset Replacement & Renewal	19,211	20,072	20,233	20,716	20,576	24,830	25,666	25,756	25,507	25,860
Asset Relocations	2,450	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029
Regulatory, Safety & Environment (other)	15,882	2,180	500	500	650	-	-	-	-	-
Quality of Supply	1,571	2,107	1,592	1,717	1,413	1,413	1,455	1,499	1,544	1,590
Subtotal - Capital Expenditure on Network Assets	**53,327**	**40,514**	**40,516**	**42,106**	**43,667**	**44,458**	**44,499**	**46,161**	**46,375**	**45,300**
Non-Network Assets	4,891	3,450	1,673	1,640	1,608	1,448	1,430	1,412	1,412	1,412
Total – Capital Expenditure on Assets	**58,218**	**43,964**	**42,188**	**43,746**	**45,275**	**45,906**	**45,929**	**47,573**	**47,786**	**46,711**

Table 12-7 Capital Expenditure Forecast
($K in constant prices)

12.2 Operational Expenditure 2019-2029

A breakdown of forecast preventative maintenance expenditure by asset category is shown in Table 12-8. This budget is relatively constant and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	116	116	116	116	116	114	114	114	114	114
Zone Substations	272	261	271	266	271	261	271	291	266	266
Distribution Poles and Lines	439	437	434	433	431	429	428	427	428	428
Distribution Cables	200	200	200	200	200	200	200	200	199	200
Distribution Substations	635	635	635	635	635	635	635	635	635	535
Distribution Switchgear	728	727	727	727	727	727	727	727	727	727
Other Network Assets	280	278	278	278	278	278	278	278	278	278
Total	**2,670**	**2,654**	**2,661**	**2,655**	**2,658**	**2,644**	**2,653**	**2,672**	**2,647**	**2,548**

Table 12-8 Preventative Maintenance by Asset Category
($K in constant prices)

The forecast corrective maintenance expenditure by asset category is shown in Table 12-9. This excludes capitalised maintenance, which is incorporated into Table 12-3. These forecasts are based on historical trends and forecast asset replacements; however year on year variances across the different asset categories will occur depending on the nature of the corrective maintenance that is required in any given year.

Asset Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	265	266	268	270	273	274	216	172	172	172
Distribution Poles and Lines	824	763	764	858	866	874	880	880	880	880
Distribution Cables	575	575	575	575	575	575	575	575	573	563
Distribution Substations	1,727	1,694	1,835	1,863	1,907	1,955	1,960	1,829	1,920	1,922
Distribution Switchgear	688	689	690	691	693	694	695	759	696	696
Other Network Assets	1,244	1,014	720	411	417	290	290	290	289	290
Total	**5,323**	**5,001**	**4,852**	**4,668**	**4,731**	**4,662**	**4,616**	**4,505**	**4,530**	**4,523**

Table 12-9 Corrective Maintenance by Asset Category ($K in constant prices)

The total forecast operational expenditure for 2019 to 2029 is shown in Table 12-10.

Category	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Service interruptions & emergencies maintenance	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836
Vegetation management	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815
Routine & corrective maintenance and inspection[78]	9,948	9,963	9,963	9,963	9,963	9,963	9,963	9,963	9,963	9,963
Asset replacement & renewal maintenance	818	818	818	818	818	818	818	818	818	818
Subtotal –Operational Expenditure on Network Assets	**16,417**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**	**16,432**
Non-network Operational Expenditure	17,516	17,575	17,215	17,215	17,215	17,215	17,215	17,215	17,215	17,215
Total – Operational Expenditure	**33,933**	**34,007**	**33,647**	**33,647**	**33,647**	**33,647**	**33,647**	**33,647**	**33,647**	**33,647**

Table 12-10 Operational Expenditure Forecast ($K in constant price)

[78] Routine & corrective maintenance and inspection expenditure also allows for emerging technology & SCPP Opex costs.

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 or in response the final decision of the Commission regarding the SCPP application.	Allowance has been made for seismic building reinforcement in order to meet legislative requirements. Assumption has also been made that the SCPP application under review with the Commission will be approved.	The SCPP application was approved and WELL is on track to deliver the SCPP program.
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. The strategy for overhead line assets has been updated in 2017 and 2018 to include a greater focus on predictive analysis. Further work on predictive analysis of overhead conductors and underground cables will continue in 2019.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Operational Expenditure - Routine Inspection and Maintenance	Any material change to the annual maintenance programme 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, though the change to the FSA has meant an increase in Opex expenditure. Managing mature network assets, the routine of inspection and servicing is not likely to change significantly.	The inspection programme is defined by comprehensive maintenance standards covering all asset classes. Rates are set in the new Field Services Agreement (FSA) started in 2019 which is at a higher level than previous.
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 in the new contract.
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 2015/16 to 2019/20 were set by the Commission's 2014 DPP Determination. It is assumed that the targets will increase in the 2020 Determination due to the changes in the HSW Act.	The targets adopted in this plan align with the Commission's 2014 determination until 2020 and reflect WELL's intention to maintain network reliability at current levels. Future targets will be dependent on the impact of the HSW Act and the changing work practices that have made a material change in the amount of work that is undertaken de-energised.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
Regulatory environment	A change to the regulatory environment may lead to increased or decreased ability to recover on investments.	The regulatory environment will continue to incentivise shareholders to invest in the network to ensure a sustainably profitable business. New requirements relating to the HSW Act will not significantly alter costs.	The expected impact of the 2014 DPP reset has been assessed, providing stability through to 2020. As WELL is committed to implementing best practice in workplace health and safety, compliance with the HSW Act will not materially increase costs.
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.
Transmission Pricing	Changes to the methods of transmission pass-through pricing may lead to increased expenditure as grid alternative options become more attractive in a non-pass-through environment.	The transmission pricing methodologies will remain largely unchanged and the transmission pass-through pricing will remain in place.	Transmission pricing is regulated as a pass-through cost and our expectation that this will remain as a pass-through cost with the net effect to the business remaining the same. The outcome of current consultation by the Electricity Authority on TPM is yet to be determined.
Economy	An increase in the cost of raw materials and imported equipment could cause an increase in investment costs, or lead to deferral of projects to remain within budgets.	The commodity markets will remain stable during the forecast period limiting equipment price rises. GDP growth in the area supplied by 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.

Area	Possible impact and variation to plan	Assumption	Reason for assumption
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 2018 Plan

During the past year, WELL has continued the review of its asset management strategy and practices. Progress against the gaps identified in the 2018 AMP, along with material changes to network development and lifecycle asset management plans, is shown in the table below.

2018 AMP Section	Item	Description
3.7.1.4	Use of Network Agreement	Revise Use of Network Agreement in consideration of Electricity Authority's proposed Default Distributor Agreement and commence negotiations with retailers using the network.
		On Hold: This work is on hold pending the commencement of consultation by the Electricity Authority on Default Distributor Agreements. Consultation will commence after the Court of Appeal decision on whether the Electricity Authority has the power to introduce a DDA.
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 16 buildings left to be addressed on this programme.
11.3.3.3	Resilience of Central Park to HILP events	Additional risk controls to be implemented as part of the plan agreed between WELL and Transpower. A list of potentially high cost solutions will be discussed with stakeholders as part of resiliency work.
		In Progress: Engagement with business leaders in 2016 resulted in the resilience of Central Park forming a central component of the resilience project as discussed in Section 11. Work with Transpower and other stakeholders on long term option development.

2018 AMP Section	Item	Description
11.5	33kV Overhead Emergency Corridors	Completion of designs for the remaining overhead sub-transmission routes and consultation with WCC to gain approval for these routes.
		In Progress: Wellington city routes have been developed with initial scoping of additional routes in other network areas. Development of emergency corridors in Northeastern and Northwestern network areas began in 2018 and will continue into 2019. Field trial of the surface foundation has been completed and manufacturing drawings are being produced. Mass production has begun as part of the SCPP programme.
11.5	Resiliency Business Case	Develop a business case assessing options to improve the readiness of the network to High Impact Low Probability events.
		In Progress: WELL has completed a business case identifying options to improve readiness in the event of a major disaster in the region. This formed the basis of the SCPP programme which will be completed by 2021.
7.2	Asset Lifecycle Planning	Continued development of asset lifecycle plans to risk-based asset strategies for all asset categories.
		In Progress: Further developments of the asset fleet strategies for overhead networks have been completed in 2017, with work on the 11kV cable fleet strategy completed in 2018. Secondary assets and Distribution equipment are to be completed in 2019.
7.5.1	Sub-transmission Health and Criticality Analysis	A project will be initiated to remove the Evans Bay 1 circuit from service.
		In Progress: A detailed study in 2016 identified a range of options for resolving the health of the Evans Bay 1 circuit. The rate of leakage is being closely monitored and is currently manageable, and removal from service is now planned for 2022, following the completion of the Evans Bay 33kV change-over bus project and the Wellington Southern area sub-transmission reconfiguration.

2018 AMP Section	Item	Description
7.5.2	Zone Substation Transformer Health and Criticality Analysis	The Evans Bay transformers are anticipated to be replaced to be replaced with new transformers by 2022.
		In Progress: The business case for the replacement of these transformers was prepared, presented and approved at both CIC and the Board in 2017. The feasibility study for the replacement of the transformers was completed in 2018 and detailed design is due to begin in 2019.
7.5.2	Zone Substation Transformer Health and Criticality Analysis	An acoustic wall design will be investigated in 2017 to deal with noise levels at the substation.
		Update: An acoustic wall design will be investigated when the major works are undertaken at the zone substation to deal with the noise levels.
7.5.2	Zone Substation Circuit Breaker Health and Criticality Analysis	Reyrolle Type C circuit breakers at Gracefield are to be replaced over the next two years.
		Update: Replacement switchgear has been procured and the project construction is currently underway and due for completion by end of 2019.
7.5.2	Zone Substation Circuit Breaker Health and Criticality Analysis	Further testing after PD mitigation work has identified circuit breakers with high PD that was previously masked.
		Update: PD mitigation works have been undertaken in 2018. Additional PD works to happen in middle of 2019. Apart from the PD the switchgear is in good condition but has high criticality due to location in Wellington CBD.
7.5.2	Zone Substation Circuit Breaker Health and Criticality Analysis	The switchboard at Kaiwharawhara has shown intermittent PD without consistent location, the PD will continue to be monitored.
		Update: Testing in 2017 identified PD within the CB17 compartment. Test results from continuous monitoring in 2018 are pointing to external sources of PD. Regular PD testing as part of maintenance to continue, starting in 2019.
7.5.6	Ground Mounted Switchgear Health and Criticality Analysis	Magnefix units with low grease level in the termination may be a sign of heating at the termination. These units are prioritised for re-termination.
		Update: Magnefix units with low grease are prioritised for grease top-up.

2018 AMP Section	Item	Description
7.5.8.3	Load Control Replacement Strategy	WELL is reviewing its load control strategy, which may recommend additional investment in load control assets.
		In Progress: A draft strategy has been developed for the future of the overall load control system on the network. Work to refine and gain approval for this strategy will continue in 2019.
8.1.8	Non-Network Solution Policy	Introducing a new tariff structure to incentivise consumers to use new technologies in a way that smooths peak demand.
		Update: Special EV tariff implemented and investigation into battery storage tariff initiated. Start a trial project on conceptual design and field trial of an energy balancing system.
8.1.9.1	Connection Policy	Update standards by developing a distributed generation connection guideline.
		Update: Interim DG connection guideline implemented awaiting publication of the EEA "Guideline for the Connection of Small-Scale Inverter Based Distributed Generation" and the Authority's decision on adopting the standard.
8.3	Network Development and Reinforcement Plan	An external review of the Network Development and Reinforcement Plan for the Northeastern Area was planned for 2019.
		Update: Studies to confirm system development needs commenced. The update and external review is now planned for 2020.
11.3.3.3	Central Park GXP	Long term plan to address single point of failure risks at Central Park.
		Update: Work with Transpower to implement fire detection and suppression has been trialled at Central Park. Formally engaged Transpower for Central Park 2 investigation and detailed solution development.
7.5.8.2	Substation Protection Relays	Current planned programmes and projects included in the asset replacement and maintenance budgets.

2018 AMP Section	Item	Description
		Update: The last of the Nilstat relays will be removed during the Gracefield Switchboard replacement currently under construction. Brown Owl and Maidstone Sub-Transmission replacements currently in the Feasibility Stage. Ongoing protection and control upgrades across the network will be developed in a new Secondary NDRP and their planning solidified.
7.5.8.3	SCADA and Communications Assets	Renewal and Refurbishment
		Update: Brown Owl, Maidstone and Korokoro all planned for RTU upgrades in 2019. The new Secondary NDRP details programmes for the various RTU types, and their ongoing planned upgrade timeframe. PAS replacement and SCADA radio options feasibility studies to be undertaken in 2019.
7.5.9.3	Load Control Equipment	Renewal and Refurbishment
		Update: Business case for the replacement of the Foxboro master station is near completion and will be presented in 2019. The Secondary NDRP details a replacement programme for the load control PLC's starting in 2020.
10.1.1.1	SCADA	Investigating the introduction of new software to replace the TrendSCADA data historian tool.
		Ongoing: Investigation into potential alternative software is ongoing. New software will be interfaced with SCADA and load control platform, also support the development requirements of an energy balancing system.
10.1.1.1	Automatic Load Control System	Undertake further investigation and planning into the replacement for the Foxboro automatic load control system.
		Ongoing: Investigation into potential alternative software is complete and a Business Case is being prepared.
10.5	Deuar pole-testing license	Extending the Deuar pole-testing licenses.
		Complete: The Deuar pole-testing licenses have been extended.

Figure B-1 Progress against Actions Identified in 2018 AMP

Comparisons between forecast expenditure from the 2018 AMP and the actual expenditure for the 2018/19 regulatory year are shown below in Figure B-2 for operational expenditure and Figure B-3 for capital expenditure.

Expenditure Category	2018/19 Forecast from 2018 AMP	2018/19 Actuals	Variation
Service Interruptions and Emergencies	4,051	4,220	+169
Vegetation Management	1,718	1,968	+250
Routine and Corrective Maintenance and Inspection	7,333	10,509	+3,176
Asset Replacement and Renewal	1,631	818	-813
System Operations and Network Support	4,893	5,606	+713
Business Support	12,405	10,499	-1,906
Operational expenditure	**32,031**	**33,620**	**+1,589**

Figure B-2 Comparison of Operational Expenditure against 2018 AMP Forecasts ($K, forecast in nominal dollars)

Operating expenditure was approximately 5% higher than forecast mainly due to increased routine and corrective maintenance expenditure associated with repairing the Titahi Bay cable fluid leak and a categorisation issue between this and Business Support in the 2018 AMP. The expenditure on Business Support has been lower than forecast due to writing off a provision for the lease associated with WELL's previous headquarters and the aforementioned categorisation issue.

Expenditure Category	2018/19 Forecast from 2018 AMP	2018/19 Actuals	Variation
Consumer Connection	7,111	9,872	+2,761
System Growth	4,359	1,001	-3,358
Asset Replacement and Renewal	18,595	23,363	+4,768
Asset Relocations	2,238	1,806	-432
Reliability, Safety and Environment	11,157	13,349	+2,192
Expenditure on Non-network Assets	3,450	745	-2,705
Capital Expenditure	**46,910**	**50,136**	**3,226**

Figure B-4 Comparison of Capital Expenditure against 2018 AMP Forecasts ($K, forecast in nominal dollars)

Significant variations between forecast capital expenditure and actual expenditure were as follows:

- A variation of $2.7 million in Consumer Connection expenditure due to a general uplift in development activity across the region;
- A variation of $3.3 million in System Growth expenditure due to a deferral of expenditure for the Frederick Street sub transmission cable project so that further feasibility studies could be done to GPR the entire cable route;
- A variation of $4.8 million in Asset Replacement and Renewal due to bringing forward some high priority asset replacements;
- A variation of $2.2 million in Reliability, Safety and Environmental expenditure which was driven by bringing some of the SCPP delivery forward; and
- A variation of $2.7 million in Non-Network Assets due to the delays with the GIS upgrade whilst various software options are evaluated.

Appendix C Schedules

Company Name	**Wellington Electricity Lines Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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 19**	**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**
9		**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection		9,872	8,189	8,575	9,805	11,078	11,362	11,590	11,965	12,368	12,769	13,129
11		System growth		1,001	6,309	6,378	7,588	7,707	9,826	6,813	5,801	7,499	7,947	6,156
12		Asset replacement and renewal		23,363	19,595	20,883	21,472	22,424	22,717	27,963	29,482	30,178	30,483	31,523
13		Asset relocations		1,806	2,499	1,855	1,911	1,969	2,029	2,111	2,196	2,285	2,377	2,473
14		Reliability, safety and environment:												
15		Quality of supply		2,805	1,602	2,192	1,689	1,858	1,560	1,591	1,672	1,756	1,845	1,939
16		Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment		10,544	16,200	2,268	531	541	718	-	-	-	-	-
18		**Total reliability, safety and environment**		13,349	17,802	4,460	2,220	2,399	2,278	1,591	1,672	1,756	1,845	1,939
19		**Expenditure on network assets**		49,391	54,393	42,151	42,995	45,577	48,212	50,067	51,115	54,085	55,421	55,219
20		Expenditure on non-network assets		745	4,989	3,589	1,775	1,775	1,775	1,631	1,643	1,654	1,687	1,721
21		**Expenditure on assets**		50,136	59,382	45,740	44,770	47,352	49,987	51,698	52,758	55,739	57,109	56,941
22														
23	*plus*	Cost of financing		168	179	177	174	172	197	218	223	225	227	232
24	*less*	Value of capital contributions		6,151	7,151	6,706	7,275	7,816	6,762	7,718	7,718	7,812	7,917	8,014
25	*plus*	Value of vested assets												
26														
27		**Capital expenditure forecast**		44,154	52,410	39,211	37,670	39,708	43,423	44,198	45,262	48,152	49,419	49,159
28														
29		Assets commissioned		44,154	52,410	39,211	37,670	39,708	43,423	44,198	45,262	48,152	49,419	49,159
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 19**	**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**
32				**$000 (in constant prices)**										
33		Consumer connection		9,872	8,028	8,242	9,240	10,234	10,291	10,291	10,416	10,556	10,685	10,771
34		System growth		1,001	6,185	6,130	7,150	7,120	8,900	6,050	5,050	6,400	6,650	5,050
35		Asset replacement and renewal		23,363	19,211	20,072	20,233	20,716	20,576	24,830	25,666	25,756	25,507	25,860
36		Asset relocations		1,806	2,450	1,783	1,801	1,819	1,837	1,874	1,912	1,950	1,989	2,029
37		Reliability, safety and environment:												
38		Quality of supply		2,805	1,571	2,107	1,592	1,717	1,413	1,413	1,455	1,499	1,544	1,590
39		Legislative and regulatory		-	-	-	-	-	-					
40		Other reliability, safety and environment		10,544	15,882	2,180	500	500	650	-	-	-	-	-
41		**Total reliability, safety and environment**		13,349	17,453	4,287	2,092	2,217	2,063	1,413	1,455	1,499	1,544	1,590
42		**Expenditure on network assets**		49,391	53,327	40,514	40,516	42,106	43,667	44,458	44,499	46,161	46,375	45,300
43		Expenditure on non-network assets		745	4,891	3,450	1,673	1,640	1,608	1,448	1,430	1,412	1,412	1,412
44		**Expenditure on assets**		50,136	58,218	43,964	42,189	43,746	45,275	45,906	45,929	47,573	47,787	46,712
45														
46		**Subcomponents of expenditure on assets (where known)**												
47		Energy efficiency and demand side management, reduction of energy losses												
48		Overhead to underground conversion												
49		Research and development												
50														

Difference between nominal and constant price forecasts	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24	CY+6 31 Mar 25	CY+7 31 Mar 26	CY+8 31 Mar 27	CY+9 31 Mar 28	CY+10 31 Mar 29
for year ended / $000											
Consumer connection	-	161	333	566	844	1,071	1,298	1,549	1,812	2,085	2,359
System growth	-	124	248	438	587	926	763	751	1,099	1,297	1,106
Asset replacement and renewal	-	384	811	1,238	1,708	2,142	3,133	3,816	4,421	4,976	5,663
Asset relocations	-	49	72	110	150	191	236	284	335	388	444
Reliability, safety and environment:	-	-	-	-	-	-	-	-	-	-	-
Quality of supply	-	31	85	97	141	147	178	216	257	301	348
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	318	88	31	41	68	-	-	-	-	-
Total reliability, safety and environment	-	349	173	128	183	215	178	216	257	301	348
Expenditure on network assets	-	1,067	1,637	2,480	3,471	4,545	5,609	6,616	7,924	9,047	9,920
Expenditure on non-network assets	-	98	139	102	135	167	183	213	242	275	309
Expenditure on assets	-	1,164	1,776	2,582	3,606	4,712	5,792	6,829	8,166	9,323	10,229

11a(ii): Consumer Connection

for year ended	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
*Consumer types defined by EDB**	$000 (in constant prices)					
Substation	2,566	4,289	4,356	4,356	4,708	4,732
Subdivision	4,599	2,379	2,496	3,475	4,087	4,100
High Voltage Connection	93	133	136	139	141	144
Residential Customers	2,458	1,127	1,154	1,170	1,198	1,215
Public Lighting	157	100	100	100	100	100
**include additional rows if needed*						
Consumer connection expenditure	9,872	8,028	8,242	9,240	10,234	10,291
less Capital contributions funding consumer connection	4,613	6,181	6,930	7,676	7,718	7,718
Consumer connection less capital contributions	5,260	1,847	1,312	1,564	2,516	2,573

11a(iii): System Growth

	Current Year CY 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
Subtransmission	422	2,800	3,100	2,200	-	-
Zone substations	4	1,400	1,760	1,900	3,200	2,600
Distribution and LV lines		-	-	-	-	-
Distribution and LV cables	575	1,000	600	2,000	2,600	4,100
Distribution substations and transformers		-	-	-	-	-
Distribution switchgear		-	-	-	-	-
Other network assets		985	670	1,050	1,320	2,200
System growth expenditure	1,001	6,185	6,130	7,150	7,120	8,900
less Capital contributions funding system growth						
System growth less capital contributions	1,001	6,185	6,130	7,150	7,120	8,900

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**

11a(iv): Asset Replacement and Renewal

		$000 (in constant prices)					
	Subtransmission	308	350	350	350	350	350
	Zone substations	1,200	3,250	2,550	1,550	2,300	300
	Distribution and LV lines	11,693	8,050	8,155	8,260	8,765	9,171
	Distribution and LV cables	3,220	300	950	750	1,950	1,000
	Distribution substations and transformers	2,568	2,100	1,850	2,213	2,311	3,500
	Distribution switchgear	4,065	3,178	3,091	3,450	1,835	3,350
	Other network assets	309	1,983	3,126	3,660	3,205	2,905
	Asset replacement and renewal expenditure	23,363	19,211	20,072	20,233	20,716	20,576
less	Capital contributions funding asset replacement and renewal						
	Asset replacement and renewal less capital contributions	23,363	19,211	20,072	20,233	20,716	20,576

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**

11a(v):Asset Relocations

	*Project or programme**	$000 (in constant prices)					
	Asset Relocations	793	2,450	1,783	1,801	1,819	1,837
	[Description of material project or programme]	253					
	[Description of material project or programme]	312					
	[Description of material project or programme]	-					
	[Description of material project or programme]	-					
	**include additional rows if needed*						
	All other project or programmes - asset relocations	449					
	Asset relocations expenditure	1,806	2,450	1,783	1,801	1,819	1,837
less	Capital contributions funding asset relocations	1,538	1,470	1,070	1,081	1,091	1,102
	Asset relocations less capital contributions	269	980	713	720	727	735

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**

11a(vi):Quality of Supply

	*Project or programme**	$000 (in constant prices)					
	Reliability Improvement Projects	2,805	1,571	2,107	1,592	1,717	1,413
	[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 - quality of supply						
	Quality of supply expenditure	2,805	1,571	2,107	1,592	1,717	1,413
less	Capital contributions funding quality of supply						
	Quality of supply less capital contributions	2,805	1,571	2,107	1,592	1,717	1,413

11a(vii): Legislative and Regulatory

Project or programme*	Current Year CY for year ended 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
	$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

Project or programme*	Current Year CY for year ended 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
	$000 (in constant prices)					
Seismic Strengthening	9,721	2,770	470	500	500	650
Streamlined CPP	823	13,112	1,710	-	-	-
[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	10,544	15,882	2,180	500	500	650
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	10,544	15,882	2,180	500	500	650

11a(ix): Non-Network Assets

	Current Year CY for year ended 31 Mar 19	CY+1 31 Mar 20	CY+2 31 Mar 21	CY+3 31 Mar 22	CY+4 31 Mar 23	CY+5 31 Mar 24
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Software	60	1,342	1,096	1,237	1,210	1,188
IT Infrastructure	66	419	404	436	430	420
Streamlined CPP	403	3,130	1,950	-	-	-
[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	529	4,891	3,450	1,673	1,640	1,608
Atypical expenditure						
*Project or programme**						
Office Equipment	215					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
*include additional rows if needed						
All other projects or programmes - atypical expenditure						
Atypical expenditure	215	-	-	-	-	-
Expenditure on non-network assets	745	4,891	3,450	1,673	1,640	1,608

Company Name	**Wellington Electricity Lines Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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 19**	**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**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	4,220	3,913	3,991	4,071	4,152	4,235	4,320	4,406	4,494	4,584	4,676
11	Vegetation management	1,968	1,851	1,888	1,926	1,965	2,004	2,044	2,085	2,127	2,169	2,212
12	Routine and corrective maintenance and inspection	10,509	10,147	10,366	10,573	10,784	11,000	11,220	11,445	11,673	11,906	12,145
13	Asset replacement and renewal	818	834	851	868	885	903	921	940	958	978	997
14	**Network Opex**	17,514	16,745	17,096	17,438	17,787	18,142	18,505	18,875	19,252	19,637	20,030
15	System operations and network support	5,606	5,884	6,029	6,150	6,273	6,398	6,526	6,657	6,790	6,926	7,064
16	Business support	10,499	11,982	12,256	12,119	12,361	12,609	12,861	13,118	13,380	13,648	13,921
17	**Non-network opex**	16,105	17,866	18,285	18,269	18,634	19,007	19,387	19,775	20,170	20,574	20,985
18	**Operational expenditure**	33,619	34,612	35,381	35,706	36,421	37,149	37,892	38,650	39,422	40,211	41,015

		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 19**	**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**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	4,220	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836	3,836
23	Vegetation management	1,968	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815	1,815
24	Routine and corrective maintenance and inspection	10,509	9,948	9,963	9,963	9,963	9,963	9,963	9,963	9,963	9,963	9,963
25	Asset replacement and renewal	818	818	818	818	818	818	818	818	818	818	818
26	**Network Opex**	17,514	16,417	16,432	16,432	16,432	16,432	16,432	16,432	16,432	16,432	16,432
27	System operations and network support	5,606	5,769	5,795	5,795	5,795	5,795	5,795	5,795	5,795	5,795	5,795
28	Business support	10,499	11,747	11,780	11,420	11,420	11,420	11,420	11,420	11,420	11,420	11,420
29	**Non-network opex**	16,105	17,516	17,575	17,215	17,215	17,215	17,215	17,215	17,215	17,215	17,215
30	**Operational expenditure**	33,619	33,933	34,007	33,647	33,647	33,647	33,647	33,647	33,647	33,647	33,647
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	1,259	1,008	1,008	1,008	1,008	1,008	1,008	1,008	1,008	1,008	1,003

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 19**	**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**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	77	155	235	316	399	484	570	658	748	840
43	Vegetation management	-	36	73	111	150	189	229	270	312	354	397
44	Routine and corrective maintenance and inspection	-	199	403	610	821	1,037	1,257	1,481	1,710	1,944	2,182
45	Asset replacement and renewal	-	16	33	50	67	85	103	122	140	160	179
46	**Network Opex**	-	328	664	1,006	1,355	1,710	2,073	2,443	2,821	3,206	3,598
47	System operations and network support	-	115	234	355	478	603	731	862	995	1,131	1,269
48	Business support	-	235	476	699	941	1,189	1,441	1,698	1,960	2,228	2,501
49	**Non-network opex**	-	350	710	1,054	1,419	1,792	2,172	2,560	2,955	3,359	3,770
50	**Operational expenditure**	-	679	1,374	2,059	2,774	3,502	4,245	5,003	5,776	6,564	7,368

Company Name	**Wellington Electricity Lines Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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.	0.01%	0.88%	40.87%	29.50%	28.74%	12.77%	3	1.42%
11	All	Overhead Line	Wood poles	No.	0.49%	8.64%	76.41%	8.67%	5.79%	12.27%	3	13.77%
12	All	Overhead Line	Other pole types	No.				52.63%	47.37%		4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		5.76%	90.45%	1.11%	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				60.00%	40.00%		3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km		5.00%	95.00%				3	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km		18.75%	81.25%				3	5.64%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km				100.00%			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.			100.00%				3	-
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.							N/A	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.		3.55%	78.69%	17.76%			3	3.55%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
35												

36 **Asset condition at start of planning period (percentage of units by grade)**

37/38	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
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.85%	13.46%	69.23%	13.46%			4	3.85%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.02%	16.48%	70.03%	7.67%	5.80%		3	1.00%
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							N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km		0.12%	1.20%	11.00%	87.68%		3	1.00%
44	HV	Distribution Cable	Distribution UG PILC	km		4.98%	12.58%	65.02%	17.42%		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%	57.15%	10.71%	28.57%		3	3.57%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	2.97%	1.88%	82.96%	8.37%	3.82%		3	4.85%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.08%	5.81%	78.43%	7.61%	8.07%		3	5.89%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	2.38%	24.60%	69.85%	2.38%	0.79%		3	7.54%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1.75%	2.42%	77.70%	12.26%	5.87%		3	4.17%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.33%	1.48%	41.02%	38.77%	18.40%		3	1.81%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.		0.78%	69.97%	29.25%			3	1.83%
53	HV	Distribution Transformer	Voltage regulators	No.							N/A	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.14%	2.52%	65.90%	27.12%	4.32%		3	2.66%
55	LV	LV Line	LV OH Conductor	km	0.22%	14.20%	78.91%	4.97%	1.70%		2	1.00%
56	LV	LV Cable	LV UG Cable	km	0.02%	8.84%	68.11%	16.06%	6.97%		2	2.00%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.06%	14.29%	71.38%	10.84%	3.43%		1	1.00%
58	LV	Connections	OH/UG consumer service connections	No.		0.09%	96.28%	0.09%	3.54%		1	2.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)		1.92%	4.91%	75.80%	7.19%	10.18%		3	10.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2.68%	38.70%	14.56%	16.09%	27.97%		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 Lines Limited**

AMP Planning Period: **1 April 2019 - 31 March 2029**

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 %	Forecast Peak Load +5 years (MVA)	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	8 Ira St	16	21	N-1	9	78%	17	21	81%	Subtransmission circuit	Manage operationallly
10	Brown Owl	15	22	N-1	7	67%	15	22	70%	No constraint within +5 years	
11	Evans Bay	14	19	N-1	11	71%	15	19	81%	No constraint within +5 years	
12	Frederick St	28	23	N-1	13	123%	30	36	83%	No constraint within +5 years	Constraint due to Frederick St subtransmission cables. These are planned to be replaced in 2019-2020.
13	Gracefield	12	20	N-1	12	59%	12	20	62%	No constraint within +5 years	
14	Hataitai	17	22	N-1	11	77%	20	22	92%	No constraint within +5 years	
15	Johnsonville	22	21	N-1	9	104%	23	21	107%	Subtransmission circuit	After the replacement of the Ngauranga transformers in 2021-22, load will be shifted to remove this constraint.
16	Karori	14	21	N-1	7	67%	14	21	68%	No constraint within +5 years	
17	Kenepuru	11	19	N-1	9	59%	15	19	81%	No constraint within +5 years	
18	Korokoro	20	17	N-1	17	118%	21	17	126%	Subtransmission circuit	Manage operationallly
19	Maidstone	14	19	N-1	12	74%	16	19	83%	No constraint within +5 years	
20	Mana	9	16	N	12	58%	9	16	58%	Transformer	After new Pauatahanui zone substation in 2020-2022, load will be shifted to remove this constraint.
21	Moore St	24	30	N-1	14	79%	27	30	90%	Transformer	Manage operationallly
22	Naenae	15	22	N-1	11	67%	16	22	71%	No constraint within +5 years	
23	Nairn St	23	25	N-1	16	90%	23	25	93%	No constraint within +5 years	
24	Ngauranga	10	12	N-1	10	80%	10	24	40%	No constraint within +5 years	Utilisation higher after picking up some of Johnsonville load
25	Palm Grove	25	24	N-1	13	106%	23	24	97%	Transformer	Manage operationallly
20	Plimmerton	9	16	N	12	54%	9	16	55%	Transformer	
26	Porirua	21	15	N-1	14	139%	23	15	155%	Transformer	After new Pauatahanui zone substation in 2021-2022, load will be shifted to remove this constraint.
27	Seaview	14	18	N-1	12	77%	14	18	77%	No constraint within +5 years	
28	Tawa	14	16	N-1	13	89%	15	16	93%	No constraint within +5 years	
28	The Terrace	31	30	N-1	21	105%	32	30	108%	Transformer	Manage operationallly
29	Trentham	14	23	N-1	10	62%	17	23	73%	No constraint within +5 years	
30	University	20	24	N-1	21	82%	20	24	82%	No constraint within +5 years	
31	Waikowhai	13	19	N-1	10	69%	14	19	74%	No constraint within +5 years	
32	Wainuiomata	19	20	N-1	3	95%	20	20	99%	No constraint within +5 years	Manage operationallly
33	Waitangirua	13	16	N-1	11	83%	13	16	83%	No constraint within +5 years	
34	Waterloo	16	23	N-1	14	68%	16	23	67%	No constraint within +5 years	

[1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	Wellington Electricity Lines Limited
AMP Planning Period	1 April 2019 – 31 March 2029

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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**							
12	Domestic		1,210	1,210	1,210	1,210	1,210	1,210
13	Small Commercial		1,090	1,090	1,090	1,090	1,090	1,090
14	Medium Commercial		11	11	11	11	11	11
15	Large Commercial		14	14	14	14	14	14
16	Small Industrial		12	12	12	12	12	12
17	Large Industrial		1	1	1	1	1	1
18	Unmetered		47	47	47	47	47	47
19	**Connections total**		2,384	2,384	2,384	2,384	2,384	2,384
20	**include additional rows if needed*							
21	**Distributed generation**							
22	Number of connections		190	200	210	220	231	242
23	Capacity of distributed generation installed in year (MVA)		0.8	0.8	0.9	0.9	1.0	1.0
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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
27	GXP demand		524	524	525	526	527	528
28	*plus* Distributed generation output at HV and above		46	50	50	50	50	50
29	**Maximum coincident system demand**		570	574	575	576	577	578
30	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
31	**Demand on system for supply to consumers' connection points**		570	574	575	576	577	578
32	**Electricity volumes carried (GWh)**							
33	Electricity supplied from GXPs		2,180	2,180	2,184	2,188	2,192	2,197
34	*less* Electricity exports to GXPs		-	-	-	-	-	-
35	*plus* Electricity supplied from distributed generation		224	243	243	243	243	243
36	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
37	**Electricity entering system for supply to ICPs**		2,404	2,423	2,428	2,432	2,436	2,440
38	*less* Total energy delivered to ICPs		2,276	2,297	2,297	2,297	2,297	2,297
39	**Losses**		128	126	130	134	139	143
40								
41	**Load factor**		48%	48%	48%	48%	48%	48%
42	**Loss ratio**		5.3%	5.2%	5.4%	5.5%	5.7%	5.9%

Company Name	**Wellington Electricity Lines Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	3.4	5.3	5.3	6.0	6.0	6.0
12	Class C (unplanned interruptions on the network)	29.3	30.1	30.1	33.6	33.6	33.6
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.04	0.02	0.02	0.04	0.04	0.02
15	Class C (unplanned interruptions on the network)	0.50	0.53	0.53	0.55	0.55	0.55

Company Name	Wellington Electricity
AMP Planning Period	1 April 2019 - 31 March 2029
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	Wellington Electricity has an Asset Management Policy which is derived from the organisational vision and linked to the organisational strategies, objectives and targets. Wellington Electricity 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 Wellington Electricity's AM Strategy is covered in the AMP. Wellington Electricity has developed a further Fleet Strategy in 2018 in addition to the five that were completed pre-2018. Development of these 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 for the major asset classes such as power transformers, sub transmission cables and zone sub circuit breakers. In addition, further fleet strategies have been developed for overhead structures, distribution acbles and overhead components. There are 3 more strategies to be written.		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).

Company Name	Wellington Electricity
AMP Planning Period	1 April 2019 - 31 March 2029
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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AMP Planning Period	1 April 2019 - 31 March 2029
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.		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	Wellington Electricity's arrangements fully cover all necessary requirements for the efficient and cost effective implementation of the Asset Management Plan. They realistically address the resources required and timescales achievable, as well as 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	Wellington Electricity has a suite of appropriate Emergency Response Procedures and Contingency Plans in place to mitigate and manage the impact of a potential High Impact Low Probability event. These are listed and described in Section 11 of this AMP. The use of critical emergency spares is described in Section 4. 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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AMP Planning Period	1 April 2019 - 31 March 2029
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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AMP Planning Period	1 April 2019 - 31 March 2029
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Accountability for asset management responsibility from the CEO, through the GM Asset Management, and through functional Line Managers.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	An effective process exists for determining, and having in place, the resources needed for asset management functions. It can be demonstrated that resources are matched to asset management requirements.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Communication is guided through the 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	Wellington Electricity outsources a number of asset management activities, particularly with Service Delivery responsibilities. These are described in Section 4 of the 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	Wellington Electricity 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 Wellington Electricity 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 Wellington Electricity 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 to 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.		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 were again reviewed by Strata Consultants in 2015, and are reviewed annually by CHED Services.		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, Wellington Electricity 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	Wellington Electricity has staff in its office that are responsible for Legal, Regulatory, Statutory and other asset management requirements. These staff are supported by the Regulatory group in a sister company in Melbourne, Powercor and Citipower		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	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 commission-ing 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 a general inspection 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?	4	Wellington Electricity 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	Wellington Electricity 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.

Company Name	Wellington Electricity
AMP Planning Period	1 April 2019 - 31 March 2029
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	Wellington Electricity
AMP Planning Period	1 April 2019 - 31 March 2029
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 usually two areas to do comprehensive audits on each year. Further to this WELL has had its Asset Management activities and processes audited 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 WEellington Electricity and its service providers, and are logged, reviewed and discussed at weekly & bi-weekly meetings. A programme 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 are developed to analyse the perfomance and condition of assets across the whole life cycle, as well as maintenance and replacement costs, and any associated asset-related risks. Once these Asset Fleet Strategies have been developed (six have been completed thus far), they will be periodically reviewed and update to inform future AMP's.		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.

Company Name	Wellington Electricity
AMP Planning Period	1 April 2019 - 31 March 2029
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)

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Network and Non-network capital expenditure:

There is no difference between constant and nominal values in the current disclosure year ended 31 March 2019.

The difference from 2019/20 to 2028/29 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 2019.

The difference from 2019/20 to 2028/29 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 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	4.2.3 & 8.1.1-8.1.10
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**	7.5
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	7.5
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 & 7.5, 7.6
3.4 Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed	1.1
3.5 The date that it was approved by the **directors**	1.1
3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	
3.6.1 how the interests of stakeholders are identified	3.6.1
3.6.2 what these interests are	3.6.1
3.6.3 how these interests are accommodated in asset management practices	3.6.1
3.6.4 how conflicting interests are managed	3.6.2

Information Disclosure Requirements 2012 clause	AMP section
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including- 3.7.1 governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors** 3.7.2 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 3.2.3 & 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 - 1.5 & 9.2, 9.3 & 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 & 10.4
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	10.3
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	7.4 & 7.5 8.3

Information Disclosure Requirements 2012 clause	AMP section
3.13.3 measuring **network** performance.	6.1
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
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	Appendix A
3.17 The **AMP** must be structured and presented in a way that the **EDB** considers will support the purposes of **AMP** disclosure set out in clause 2.6.2 of the determination.	6.1 & 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. 3.53.5 & 8.2
4.2 a description of the **network** configuration, including- 4.2.1 identifying bulk electricity supply points and any **distributed generation** with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point; 4.2.2 a description of the **subtransmission** system fed from the bulk electricity supply points, including the capacity of **zone substations** and the voltage(s) of the **subtransmission network**(s). The **AMP** must identify the supply security provided at individual **zone substations**, by describing the extent to which each has n-x **subtransmission** security or by providing alternative security class ratings; 4.2.3 a description of the distribution system, including the extent to which it is underground; 4.2.4 a brief description of the **network**'s distribution substation arrangements; 4.2.5 a description of the **low voltage network** including the extent to which it is underground; and 4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	3.4 & 8.2.5 3.4 & 8.4 – 8.6 3.3 & 3.4 & 7.1 3.4 & 7.5.2 3.4,7.5.3,7.5.4 7.5.8-7.5.10

Information Disclosure Requirements 2012 clause	AMP section
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	8
Network assets by category 4.4 The **AMP** must describe the **network** assets by providing the following information for each asset category- 4.4.1 voltage levels; 4.4.2 description and quantity of assets; 4.4.3 age profiles; and 4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	3.4;7.1&App F 7.1 7.5 7.5
4.5 The asset categories discussed in subclause 4.4 above should include at least the following- 4.5.1 Sub transmission 4.5.2 Zone substations 4.5.3 Distribution and LV lines 4.5.4 Distribution and LV cables 4.5.5 Distribution substations and transformers 4.5.6 Distribution switchgear 4.5.7 Other system fixed assets 4.5.8 Other assets; 4.5.9 assets owned by the **EDB** but installed at bulk electricity supply points owned by others; 4.5.10 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.11 other generation plant owned by the **EDB**.	7.5.1 7.5.2 7.5.3 7.5.4 7.5.5 & 7.5.6 7.5.6 7.5.7 7.5.8 7.5.9 11.5.2.3
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

Information Disclosure Requirements 2012 clause	AMP section
6. Performance indicators for which targets have been defined in clause 5 above must include **SAIDI** and **SAIFI** values for the next 5 **disclosure years**.	6.1.1
7. Performance indicators for which targets have been defined in clause 5 above should also include- 7.1 **Consumer** oriented indicators that preferably differentiate between different consumer types; 7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	3.6 & 5.3.1 5.2 & 7.2 – 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.	3.6 & 5
9. Targets should be compared to historic values where available to provide context and scale to the reader.	6.1.1
10. Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	1 & 6
<u>**Network Development Planning**</u> 11. **AMP**s must provide a detailed description of **network** development plans, including— 11.1 A description of the planning criteria and assumptions for **network** development;	8.3
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

Information Disclosure Requirements 2012 clause	AMP section
11.7 A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision.	4.2 & 8.3
11.8 Details of demand forecasts, the basis on which they are derived, and the specific **network** locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 11.8.2 provide separate forecasts to at least the **zone substation** level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts; 11.8.3 identify any **network** or equipment constraints that may arise due to the anticipated growth in demand during the **AMP planning period**; and 11.8.4 discuss the impact on the load forecasts of any anticipated levels of **distributed generation** in a **network**, and the projected impact of any demand management initiatives.	4.2 & 8.3
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.	8.2 8.2.7 & 8.4-8.6 9.1, 9.2
11.10 A description and identification of the **network** development programme including **distributed generation** and non-network solutions and actions to be taken, including associated expenditure projections. The **network** development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months; 11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the **AMP planning period**.	8.4-8.6 7 & 8
11.11 A description of the **EDB**'s policies on **distributed generation**, including the policies for connecting **distributed generation**. The impact of such generation	8.1.9

Information Disclosure Requirements 2012 clause	AMP section
on network development plans must also be stated.	
11.12 A description of the **EDB**'s policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional **network** augmentation. These are typically approaches that would reduce **network** demand and/or improve asset utilisation; and 11.12.2 the potential for non-network solutions to address **network** problems or constraints.	8.1.8 8.4.3.1 & 8.5.3.1
<u>Lifecycle Asset Management Planning (Maintenance and Renewal)</u> 12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including— 12.1 The key drivers for maintenance planning and assumptions; 12.2 Identification of **routine and corrective maintenance and inspection** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done; 12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and 12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**.	7.2 & 7.3 7.4 7.5 7.5 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; 12.3.2 a description of innovations made that have deferred asset replacement; 12.3.3 a description of the projects currently underway or planned for the next 12 months; 12.3.4 a summary of the projects planned for the following four years (where known); and 12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**. 12.4 The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	7.2 – 7.4 8.4.3.1 7.6 7.6 7.5 – 7.6 Yes

Information Disclosure Requirements 2012 clause	AMP section
<u>**Non-Network Development, Maintenance and Renewal**</u> 13. **AMP**s must provide a summary description of material non-network development, maintenance and renewal plans, including— 13.1 a description of non-network assets; 13.2 development, maintenance and renewal policies that cover them; 13.3 a description of material capital expenditure projects (where known) planned for the next five years; 13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	 10.1 10.2 & 10.3 10.4 10.7
14. **AMP**s must provide details of risk policies, assessment, and mitigation, including— 14.1 Methods, details and conclusions of risk analysis; 14.2 Strategies used to identify areas of the **network** that are vulnerable to high impact low probability events and a description of the resilience of the **network** and asset management systems to such events; 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 E 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

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

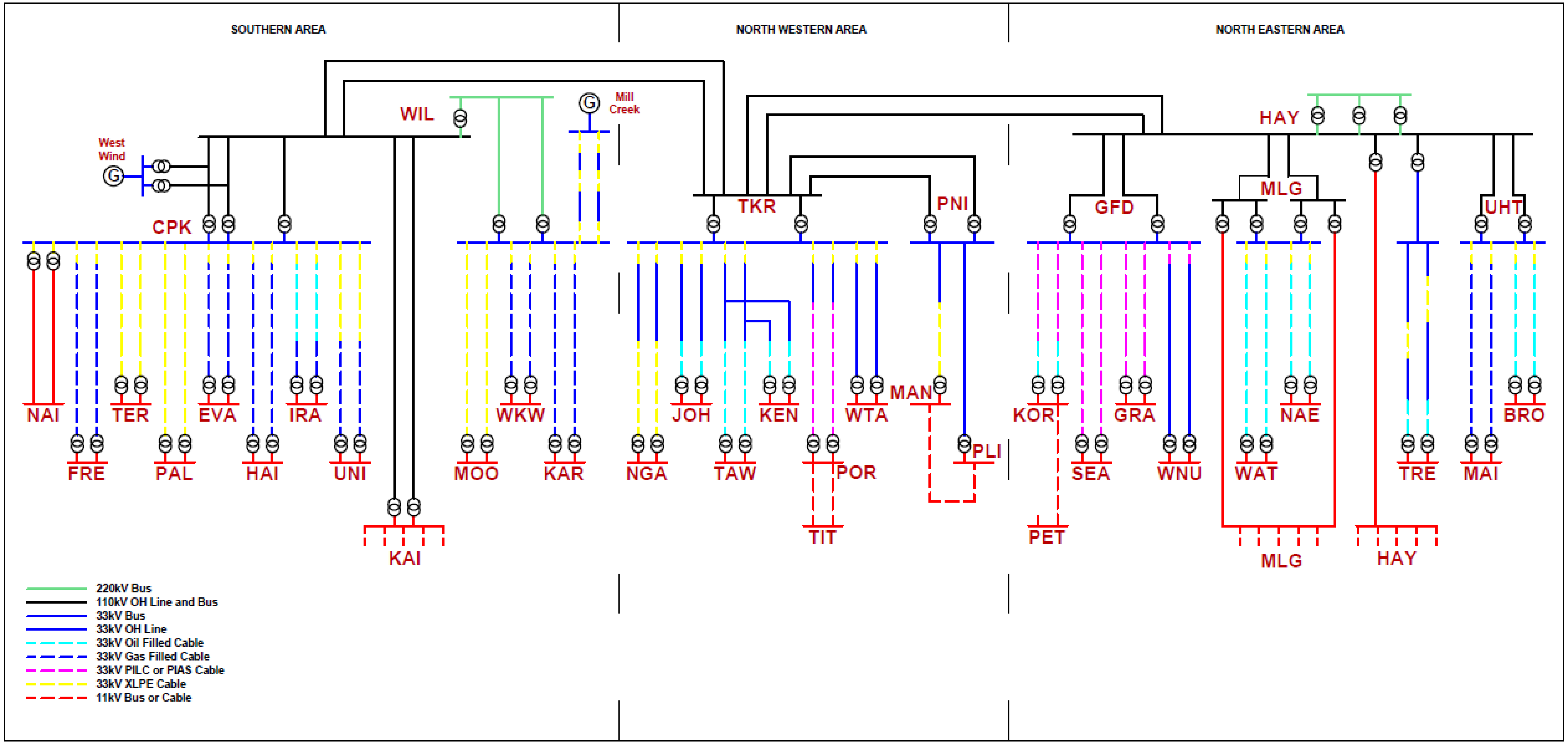
WeLG Wellington Lifelines Group

WOM Work Order Management

W/S Winter / Summer

XLPE Cross Linked Polyethylene insulation

Appendix F Single Line Diagram




DRIVE
ELECTRICITY