Wellington Electricity 10 year Asset Management Plan

1 April 2024 - 31 March 2034

Wellington Electricity

10 Year Asset Management Plan

1 April 2024 – 31 March 2034

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

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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 regulatory period 2024/25 to 2033/34. We confirm that this AMP has been prepared in accordance with the Commerce Commission's (the Commission) Electricity Distribution Information Disclosure Determination 2012 requirements.

Our operations over the last 12 months have included supporting field crews travelling for storm response in the North Island following severe weather events. The vulnerability of infrastructure to adjacent river and catchment systems was palpable and remains so for many families still affected.

As a lifeline utility, we are proud to continue to deliver our community with a safe, reliable, and secure energy delivery system under a wide range of circumstances for everyone. Resilience is a key theme in our Plan, which outlines that a suitable level is in place for our current DPP approach, however, greater investment will be required for a more resilient network as the climate changes. Preparedness for future earthquake events was undertaken in our CPP from 2018 to 2021 as critical spares were purchased and building reinforcement was undertaken as part of a Readiness, Reduction, Response, and Recovery assessment of earthquake events. This allowed 91 substation buildings to be improved in seismic resilience rating.

WELL continues to proactively engage with WorkSafe, MBIE, the Commission, the Electricity Authority, the Climate Change Commission, and the Infrastructure Commission on improvements in safety and wellbeing performance, the price-quality path reset, market regulations, and the step changes required to meet the challenges of sustainable asset investment, so that customers can continue to receive the long term benefits from secure and affordable electricity infrastructure as more expensive fossil fuels are phased out.

The path and intention to be carbon zero by 2050 through greater electrification requires increased network capacity investment. The Wellington network has operated well under a low growth Default Price Path model, however, the step change in asset replacement and new electrification capacity needs to be carefully considered. The new price path has to take advantage of a 12–15-year program of investing in subtransmission and zone substation asset replacement. Strong economic benefits occur when the end-of-life replacement of infrastructure aligns with the installation of assets with capacities calculated from 30-year population growth and decarbonisation targets driven by transport electrification and the industrial and domestic heat transition to electricity. This creates a consistent work program which will attract the workforce and supply chain required for delivery, creating cost advantages from scale and turn-key delivery schedules. A period of increased distribution asset replacement also provides increased opportunities for training and electrical apprenticeships.

A five-year price path is insufficient to deliver the lower cost benefits to customers of a scaled network investment, very similar to Transpower's build program following their "Glide Path" period. The upcoming reset is the last price path before the next decarbonisation target in 2030, and it is essential that it does not prevent EDBs from delivering the capacity that customers require for their energy transition. However, the tools the Commission requires are currently with MBIE and despite the recent review of the Input Methodoloiges, they appear to have remained there.

Unfortunately, delayed investment will stifle meeting climate change targets as well as put network quality and security at risk without the ability to provide the commensurate step change in electrification capacity.

The investment profile in this AMP looks ahead at the period until 2050 during which most of the 260,000 plus cars in the Wellington region could be fuelled from the electricity network and 55,000 residential gas connections could be replaced with electric appliances. A recent DETA Consulting survey confirmed that in the next 25 years, 100MW of thermal process heat will be replaced at industrial and commercial premises with a further 30-40MW of predominantly electric hot water heating. It is no surprise that our network in 2050 will have doubled in size to accommodate the move away from fossil fuels towards renewable electricity. Managing sharper price signals will incentivise the demand side to respond with peak congestion curtailment, through customer education and timely retailer incentives, saving customers an estimated $300m in network infrastructure investment.

Modelling of our low voltage network from a sample of purchased smart meter consumption data has been completed. This has allowed a forecast of previously invisible low voltage constraints which will require investment as households exit gas and consumers purchase electric vehicles. Different investment scenarios have been developed for various exit and uptake rates.

However, the technical smart metering data required to understand low voltage network performance remains unavailable or incomplete and unaffordable under current allowances. Increasing smart meter data availability to improve the visibility of the Low Voltage network electrical performance is critical for customer affordability and supply security. The Commission need to set allowances for low voltage network investment accordingly to meet long-term benefits for consumers.

A change in Government has seen some transport providers step back and reassess their infrastructure costs, while others continue to engage in the procurement of electric bus fleets, where 350-450 of these will each require 200kWh every night to provide public transport services the following day. Operating envelope price signals have proven valuable for managing bus charging demand within existing network capacity limits.

WELL's Time of Use (ToU) pricing for residential consumers provides retailers with a strong signal to encourage customers to move their usage away from congested peak demand periods. We appreciate retailers reflecting these signals to their customers. In future, more dynamic pricing will be needed to signal when the network requires more urgent demand reduction to remain in service. Further customer education is required to outline future services which will orchestrate their capital investments behind the meter to reduce their costs and to support less investment in building a larger network. Data access will be a key that unlocks these benefits for customers.

Quality limits will be challenged as large network reinforcement projects place areas of the network on reduced security for periods of time, with feeders being required to supply twice as many customers at N security as in their N-1 configurations as parts of the network are rebuilt. The Commission needs to address this reality and provide clear guidance on how quality targets will be reassessed for unintended supply consequences while we "rebuild the plane in flight".

We continue to invest in the network assets where they require replacement or maintenance to meet the required asset performance standards, notwithstanding the highlighted risk of lower security levels during large investment projects. Our maintenance management approach is prioritised based on asset health and asset criticality. This focuses expenditure on the highest-ranked safety and reliability risk defects. These costs are expected to increase on the back of higher supply chain and material costs, as well as increased demand through consumer growth from new subdivisions.

Health, safety, and wellbeing remain positive drivers for improved engagement with our own staff and field staff engaged under the outsourced arrangement. Maintaining awareness of hazards ahead of commencing work tasks and ensuring critical controls are exercised as part of our work ensures we have people returning to their families free from harm.

WELL continues to employ a strong team effort across planning, real-time control, and field implementation which makes this network one of the best-performing in New Zealand. Engagement continues with consumer groups on feeders experiencing vegetation outages and education on their responsibility for managing vegetation. WELL's tree management practices are benefitting from the move from the traditional notification process to a more consultative approach with tree owners. We also eagerly await the completion of MBIE's review of the Hazards from Trees Regulation.

Being a member of the CK Infrastructure Holdings Limited group allows WELL to access skills and knowledge from our other electricity distribution businesses around the world and have direct access to international best practice in asset management.

In conjunction with our service companies and in alignment with its business strategy, WELL will continue to focus on the development of its asset management strategies, in parallel with the short to long-term planning for the network, leading to sustainable investment that delivers long-term benefits for customers.

We welcome any comments or suggestions regarding this AMP.

Greg Skelton

Chief Executive Officer

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Section 1

Executive Summary

1 Executive Summary

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

1.1 Term Covered by the 2024 AMP

This AMP covers the 10-year period commencing 1 April 2024 through to 31 March 2034. It was approved by WELL's Board of Directors on 28 March 2024.

1.2 Key Elements of the 2024 AMP

Key elements of this AMP are:

- The impact of emissions reduction initiatives on the distribution network;
- Network reliability: continued focus on network reliability management; and
- Network resilience.

Appendix B provides detail on the changes made since the 2023 AMP.

1.2.1 Emissions Reduction Impacts

WELL has modelled the impact of New Zealand's Emissions Reduction Plan (ERP) and has incorporated the demand impact and service changes into its AMP planning processes. The decarbonisation programme has created significant changes to the AMP processes and forecast disclosures.

Rapid demand growth is forecast on the Wellington network, with peak demand expected to increase by 98% over the next 30 years. Aside from population growth, the primary driver is the ERP, which includes the electrification of transportation and the potential transition from natural gas to other energy sources such as electricity.

WELL's forecast capital investment profile to meet this increase in demand totals $2.2 billion over the next 30 years. Under the past business-as-usual operating environment, which has been focused on providing a steady and reliable supply of electricity, WELL's capital expenditure has averaged $42m per year for the last ten years. This is expected to increase to an average of $90m per year for the next 30 years.

WELL has developed a delivery strategy in response to changing distribution services and a step change in its future work programme. The key elements of this strategy are:

- **Continuing to refine WELL's demand growth modelling:** Providing better investment certainty by improving the accuracy of demand forecasts and future capacity requirements. This includes modelling of the low voltage network, completed during 2023, which has allowed a low voltage constraint forecast and investment programme to be included in this AMP.
- **Continue to refine WELL's future investment programme:** Ensuring the network provides the expected capacity and security.

- **Fit-for-purpose services:** Ensure WELL continues to provide distribution services customers want, at a price they are prepared to pay.
- **LV visibility and management**: Develop the ability to manage the connection of DER of the LV network and incorporate flexibility services.
- **Develop flexibility services**: To assist in uncertain demand, spread out the investment programme, and lower prices.
- **Build new delivery capability and capacity:** To deliver the large reinforcement and asset replacement programmes.
- **Co-ordinated resourcing development and materials supply chain:** Develop an industry people and materials resource plan and co-ordinate training programmes and supply chains to ensure resources are available and can be shifted to where they are needed.
- **Regulatory flexibility:** Networks need to have the allowances to deliver future distribution services at an efficient price.

1.2.2 Network Reliability

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

The reliability performance of the network in the 2023/24 year was within the range allowed by regulation.

1.2.3 Resilience Initiatives

As a lifeline utility in accordance with the Civil Defence and Emergency Management Act 2002 (CDEM Act), WELL must ensure that it is able to function to the fullest possible extent, even though this may be at a reduced capacity, during and after an emergency. This can include one-off events such as storms and earthquakes.

The funding of resilience expenditure via the DPP allowances has been challenging, and WELL welcomes the extension of reopener events in the 2023 Input Methodologies review to include reopeners for resilience expenditure. These reopeners provide an avenue for EBDs to seek funding for resilience projects in a more efficient manner than WELL was required to follow for its 2018 to 2021 Earthquake Readiness CPP.

WELL has investigated future resilience initiatives with the Wellington Lifelines Group to improve the network's ability to withstand High Impact Low Probability (HILP) events. These initiatives include:

- The evaluation of solutions with Transpower on the options to manage the single point of supply risk of the Central Park grid exit point in Brooklyn. The project is now moving ahead with Transpower establishing a project team to deliver the project by February 2027; and

- While resilience initiatives are not funded under the existing regulatory regime, expenditure for the replacement of high-vulnerability 33kV fluid-filled cables can be accelerated due to the impact of the Emissions Reduction Plan, resulting in an integrated cable replacement programme that will significantly improve the resilience of the Wellington electricity network over the next 10 years.

1.3 Service Levels

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

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

1.3.1 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 the ongoing review of health and safety practices, systems, controls (and their effectiveness) and documentation.

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

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

Planning Period Targets and Initiatives

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

- Maintain the number of addressed hazard observation events reported per annum at approximately 200;
- Maintain contractor engagement through site visit assessments at 400 per annum, while continually reducing resulting actions;
- Achieve a zero LTIFR over the whole period; and
- Achieve a zero TNEFR over the whole period.

During 2024 focus will be placed on the following areas to further improve safety performance:

- Reinforcement of WELL's safety brand "safer together";

- Increased emphasis on the Te Whare Tapa Whā principles of wellbeing (family, physical, mental, and spiritual) of staff and field workers via focussed programmes and engagements;
- Maintain the timeliness of the close-out of assessments;
- Maintain the application of the risk management framework and expand the risk assessment process with a clear focus on critical risk and control management and principal/contractor communications;
- Maintain critical risk engagement visits to:
  - check that workers have received safety instructions and have adapted work practices or processes as a result;
  - engage with workers over workplace safety and to help ensure WELL's critical risks are being effectively managed; and
  - ensure service provider workers understand all critical risk controls, especially where these interface with WELL risks.
- 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 the development of practical and effective risk controls.

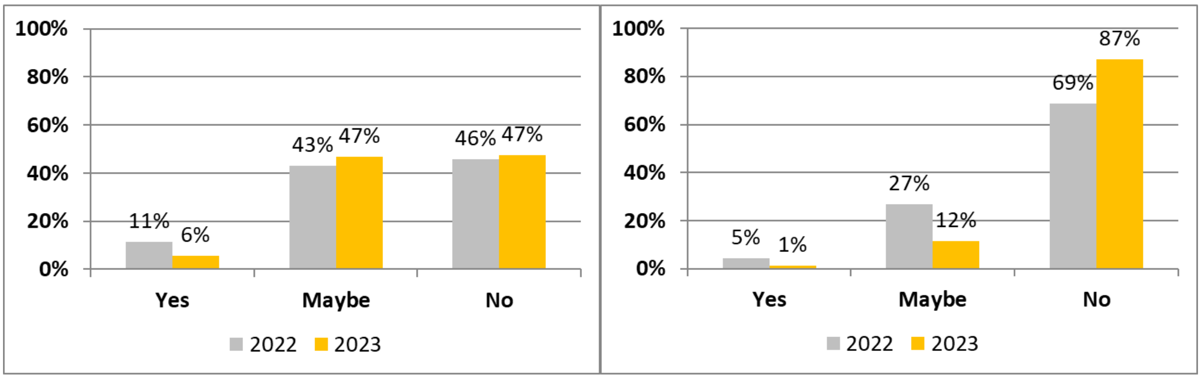
1.3.2 Customer Experience

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

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

1.3.2.1 Customer Engagement

To understand the impact of outages on connected customers, WELL surveys the communities that have recently had an outage to understand whether the price-quality trade-off of the service they receive is appropriately balanced. Examples of results for two key questions from the survey undertaken in 2023 are shown in Figure 1-1.



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

Figure 1-1 Sample of 2023 Customer Survey Results

These results suggest that customers are unwilling to pay a more for power in return for fewer power cuts, and are unwilling to experience a drop in the reliability of their power supply in response to a reduction in price.

In 2024, WELL will be delivering a number of customer experience and community engagement initiatives, with some examples being:

- **Self-service Improvement:** Continued development of the web-based self-service platform to further improve its functionality and to deliver an improved customer experience. Changes will be made to help streamline the experience for medium to large new connection and upgrade requests.

- **Service Improvement:** WELL continues to analyse and target for improvement the root causes of complaints received from customers and/or their retailers. As part of that programme, WELL staff members will visit a number of customers who have reported poor service throughout the year, in order to better understand their experiences.

- **Community Engagement:** WELL plans to continue engaging with communities most impacted by outages as part of the 'Worst Performing Feeder' programme. The programme aims to update customers on network activities in their area and inform customers of actions they can take to help improve their electricity supply, such as vegetation management. WELL also regularly engages with city councils in the Wellington region with regard to the Tree Regulations and the issuing of trim and cut notices. This is a practice that will be continued as it helps support WELL to maintain reliability levels for customers.

  WELL will pilot a customer education programme to inform customers of what actions they can take to reduce their electricity costs and mitigate the risks of energy supply constraints by shifting their electricity consumption to times of the day when the national and local networks are less busy.

  WELL will maintain a presence at trade shows to help engage with the wider community on key industry and network topics.

  In addition, as mentioned above a number of customers impacted by perceived poor service will be visited to better understand their experiences.

- **Planned (and Unplanned) Outage Publication:** As described above, a system was progressively deployed throughout 2023 to enable the semi-automation of NARs. The final phase of the project will enable the automated publication of planned outages. At the same time that this change is made, we are also enhancing the website to publish recent as well as current unplanned outages. This is in response to customer requests for greater visibility of all outages on our website.

- **Community Education:** The Government's proposals to help New Zealand reduce its carbon emission levels are likely to result in increased demand for electricity and significantly impact the network. WELL will continue to engage with and educate customers on the impacts of the government's decarbonisation targets on our network, what we are planning to respond to those changes and what customers can do to influence their levels of electricity reliability, resilience and costs.

1.3.3 Reliability Performance

The regulatory regime that applies to WELL sets reliability limits for each year. The DPP3 price-quality regime in place for 2021/22 to 2024/25 sets limits for outages based on historical performance during the reference period of 1 April 2009 to 31 March 2019.

The regulatory reliability limits for WELL are presented in Table 1-1.

Regulatory Year	2021/22-2024/25
Annual Unplanned SAIDI Limit	39.81
Annual Unplanned SAIFI Limit	0.6135
Period Planned SAIDI Limit	55.76
Period Planned SAIFI Limit	0.4429
Extreme Event - Customer Minutes Limit	6 million

Table 1-1 WELL Regulatory Reliability Limits

The SAIDI and SAIFI targets against historical performance are shown in Figure 1-2 to Figure 1-5.

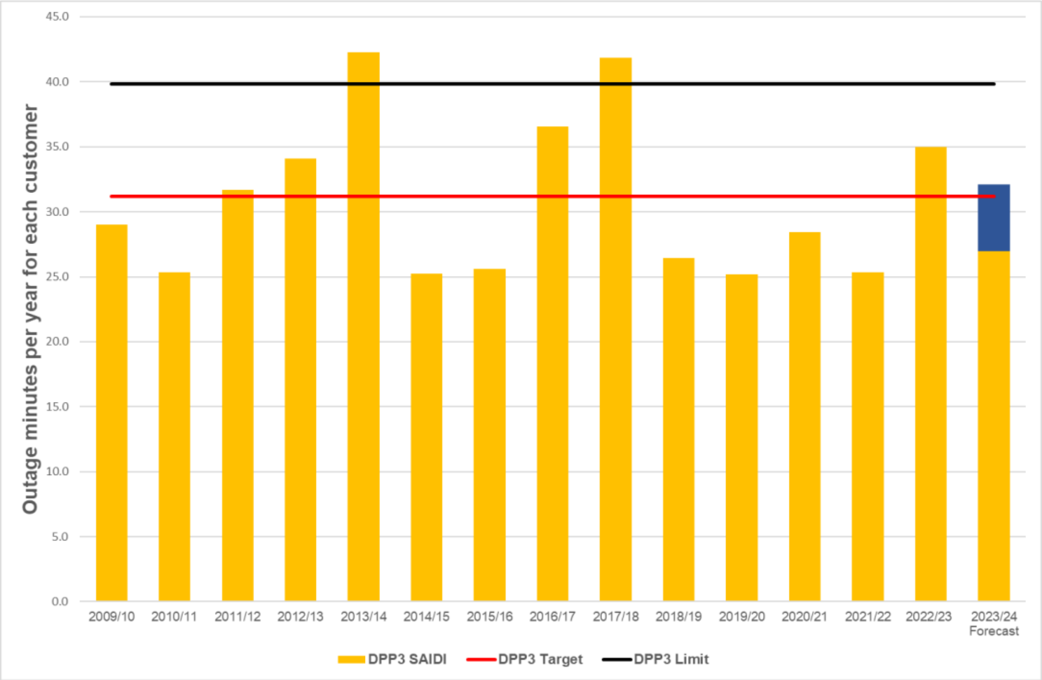


Figure 1-2 WELL Unplanned SAIDI Performance

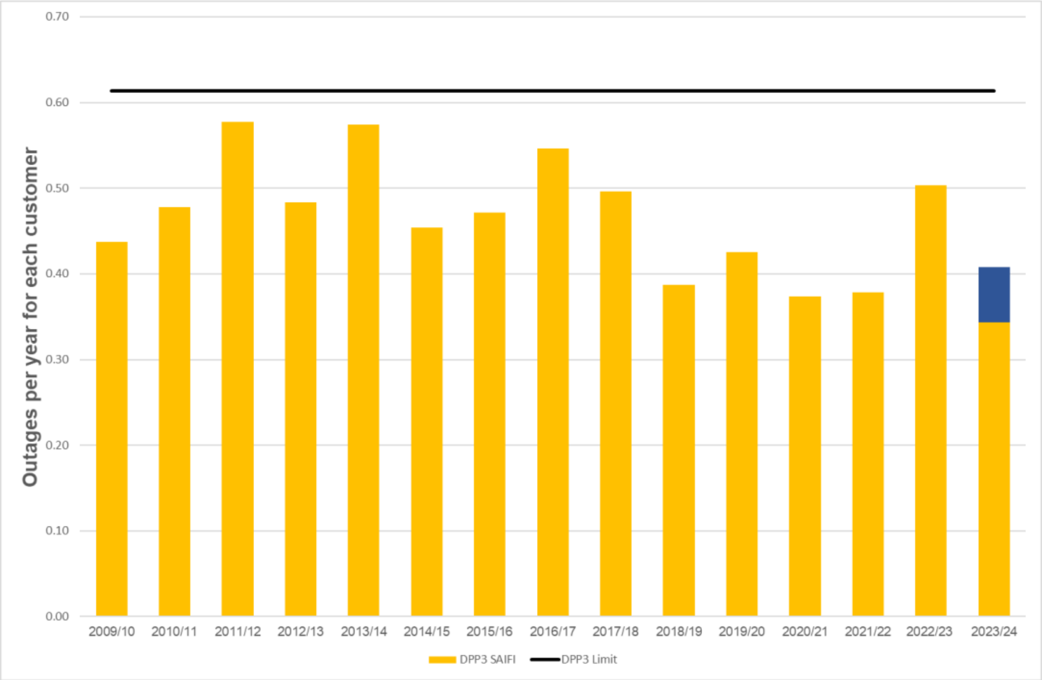


Figure 1-3 WELL Unplanned SAIFI Performance

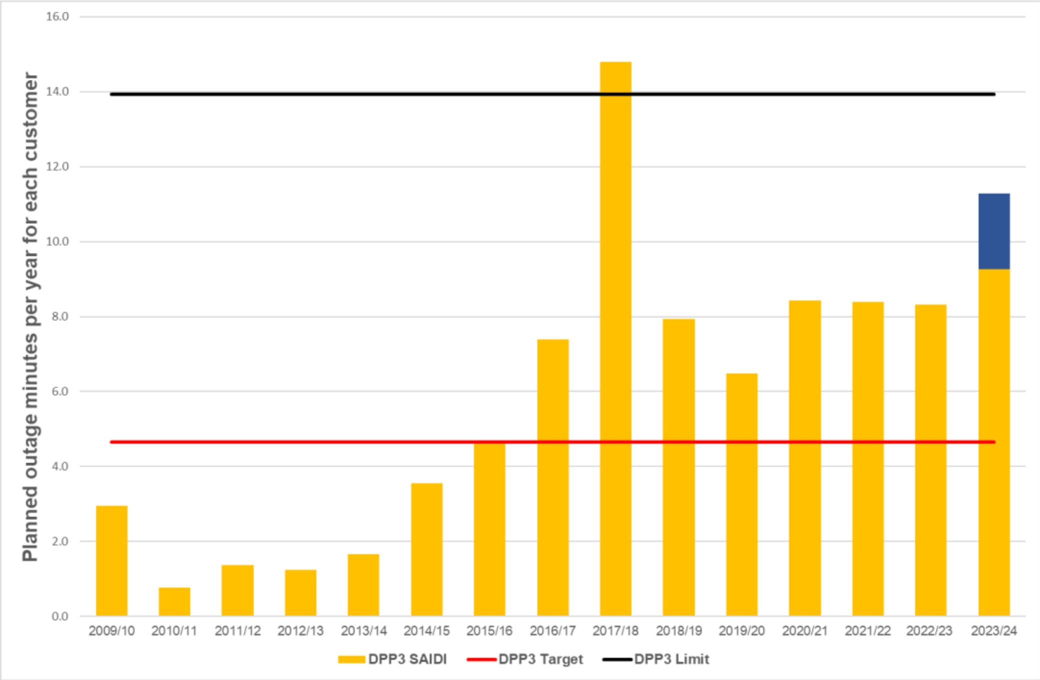


Figure 1-4 WELL Planned SAIDI Performance

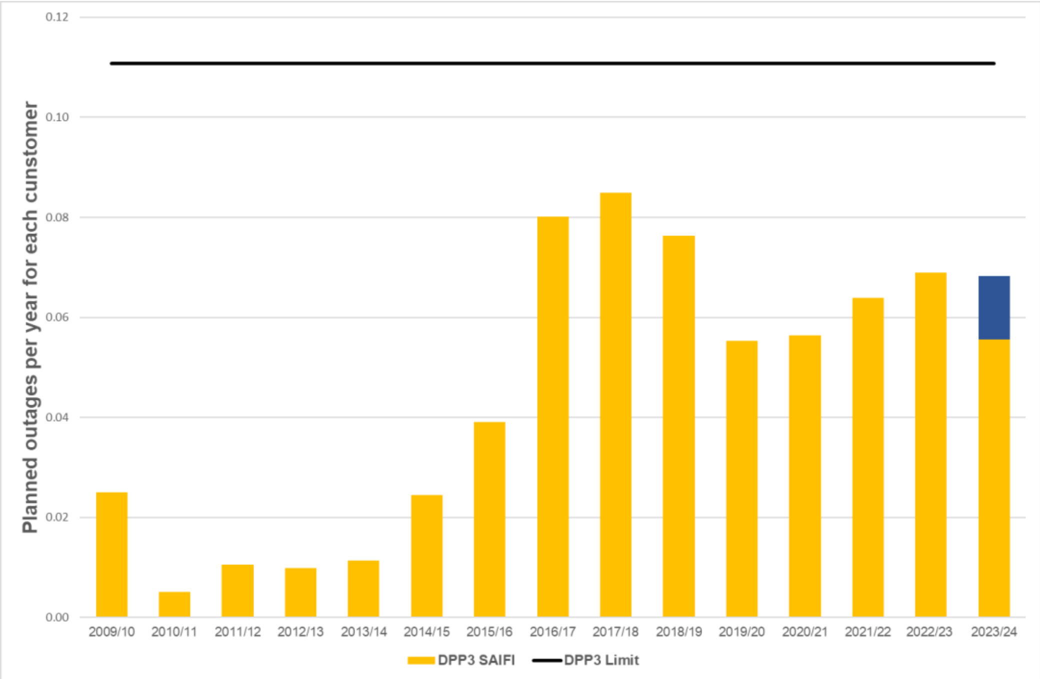


Figure 1-5 WELL Planned SAIFI Performance

WELL has consistently demonstrated a commitment to meeting reliability targets. Analysis of the main causes of network performance and WELL's initiatives to respond in future years is provided in Sections 5 and 6.

WELL's targets for SAIDI and SAIFI are shown in Table 1-2. These targets assume that the SAIDI and SAIFI targets beyond 2025 will be calculated using the same methodology as the 2019 DPP3 determination.

Regulatory Year	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Unplanned SAIDI target	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20
Unplanned SAIFI target	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480
Planned SAIDI target	12.23	17.05	17.02	16.43	15.90	15.17	15.01	14.99	15.03	15.09
Planned SAIFI target	0.068	0.095	0.095	0.091	0.088	0.084	0.083	0.083	0.084	0.084

Table 1-2 Network Reliability Performance Targets

WELL will need to increase its planned outage targets over the period due to a large increase in its work programme caused by decarbonisation load growth. While most of the increase in expenditure will be related to subtransmission and zone substation reinforcement projects that can be completed without any customer outages, there will also be a significant increase in 11 kV reinforcement, which will increase planned outage indices.

1.4 Trends in Energy Consumption and Demand

The historic volume of energy supplied through the network is shown in Figure 1-6.

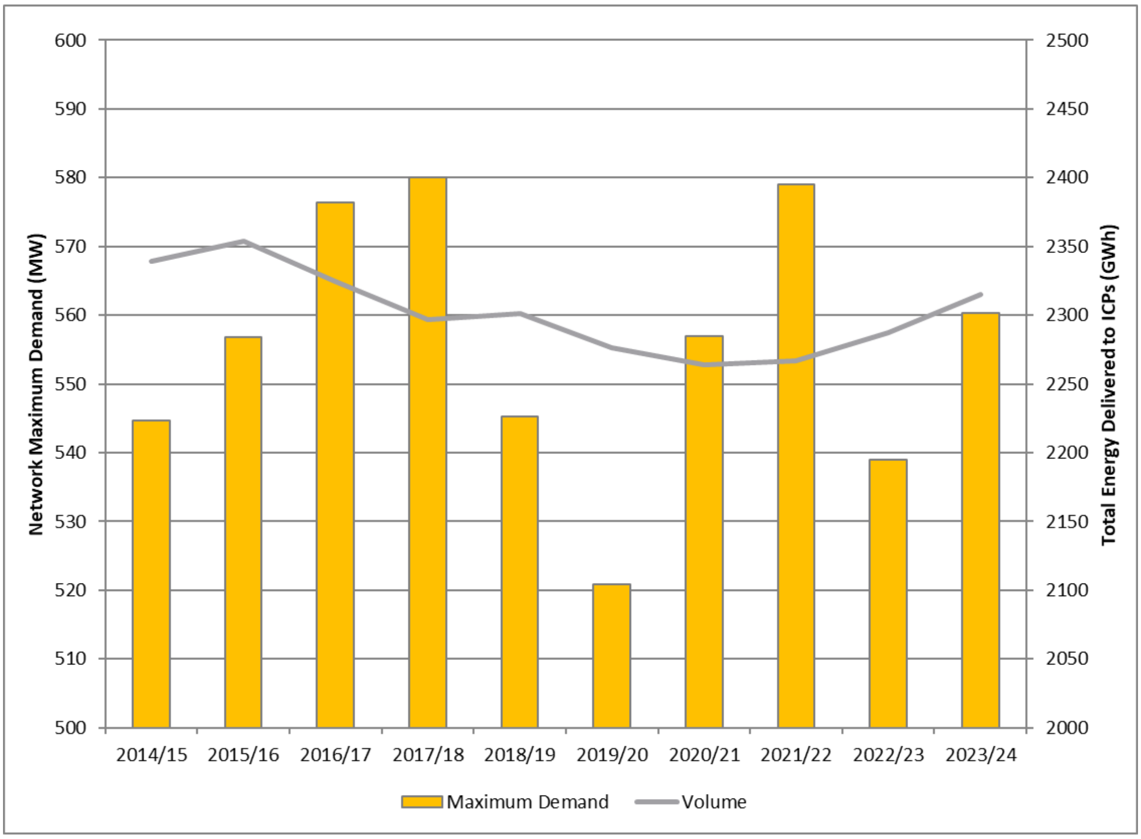


Figure 1-6 Trend in Maximum Demand and Energy Consumption

On the Wellington network, the period of maximum demand occurs in winter when household heating is at its highest. The maximum demand recorded in any particular year is therefore highly dependent on the nature of the coldest winter weekday – the colder and wetter the day, the higher the maximum demand on the network will be during the evening peak. This dependency on weather creates a significant variation in maximum demand from year to year, with there being no discernible underlying trend over the last 10 years.

Volume figures are independent of maximum demand. Whereas maximum demand is set by the weather on the worst day of the year, volume is generally driven by whether the year as a whole is milder or colder than average.

1.4.1 Demand Forecast

For several years the number of new dwellings consented annually in the Wellington region (across the four local authorities) has been increasing, driven by the growth in apartments within the Wellington CBD and subdivision growth along the northern belt. Figure 1-7 shows the number of new dwellings consented over the last seven years.

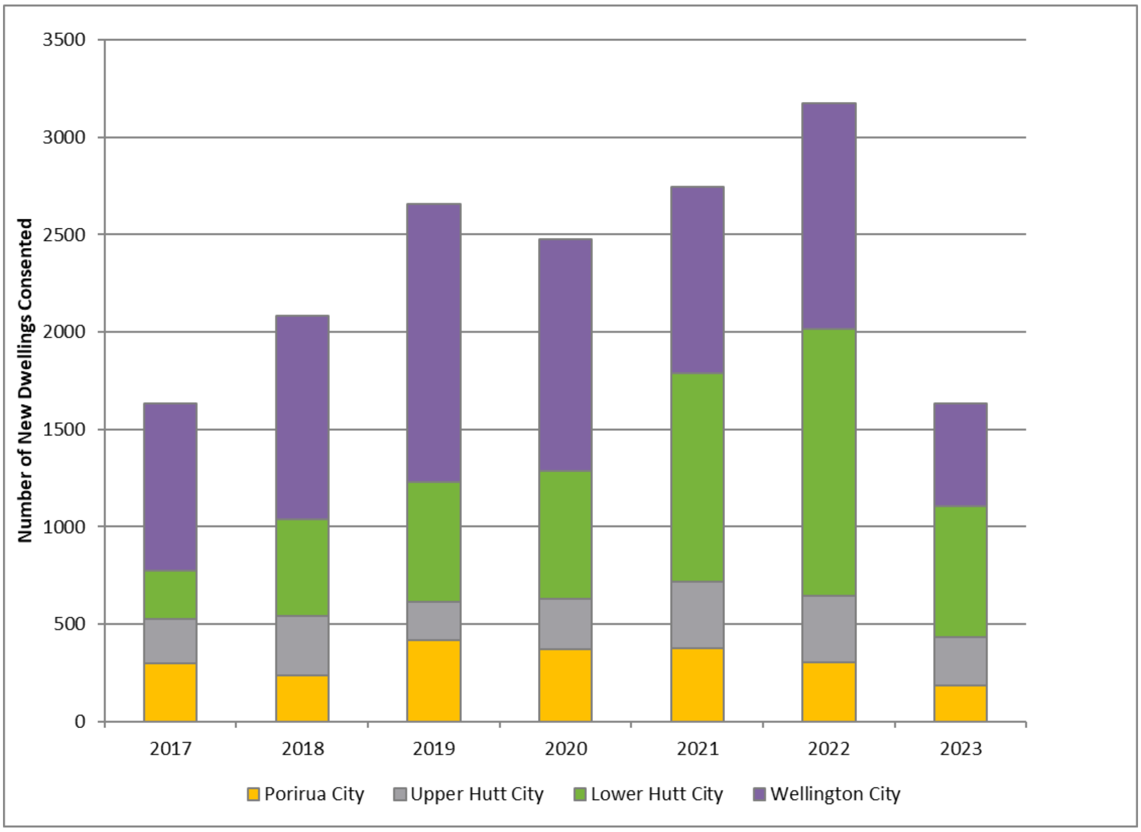


Figure 1-7 Number of New Dwellings Consented in the Wellington Region

Rapid demand growth is forecast on the Wellington network, with peak demand expected to increase by 108% over the next 30 years. Aside from population growth, the primary driver is the ERP, which includes the electrification of transportation and the potential transition from natural gas to other energy sources such as electricity.

While the magnitude of EV- and population-driven peak demand growth by 2050 can be made with a high level of confidence, the demand forecasts for electricity as a gas substitute and the demand offset from flexibility services are less certain. WELL's forecast assumes that electricity will replace fossil gas, but the ERP includes the possibility of natural gas being replaced with renewable gas sources. WELL has also forecast that flexibility services will offset some peak demand, but these services have yet to be developed to the scale needed. Table 1-3 summarises the demand forecast and the key drivers of that demand.

Growth		Assumption	98th Percentile of Demand (MW)	Total change (%)	Annual change (%)
Current Demand (2023)			**536**	**N/A**	**N/A**
Growth Source	Population Growth	Population Growth + Housing Shortage	168	31%	1.0%
	Transport Electrification	Emissions Reduction Programme	237	50%	1.5%
	Transition from Gas	Emissions Reduction Programme	237	50%	1.5%
New Growth			665	N/A	N/A
Total Demand (2053) - Uncontrolled			**1,178**	**120%**	**4.0%**
Demand-side Management		Introduction of Flexibility Services	-115	-21%	-0.7%
Total Demand (2053) - Controlled			**1,063**	**98%**	**3.3%**

Table 1-3 WELL's Demand Growth Forecast

Figure 1-8 shows this forecast peak demand growth profile to 2053. For illustrative purposes, the impact of demand-side management has been included in the baseline figure. Gas substitution has the largest impact, starting slowly and rapidly increasing in the late 2030s.

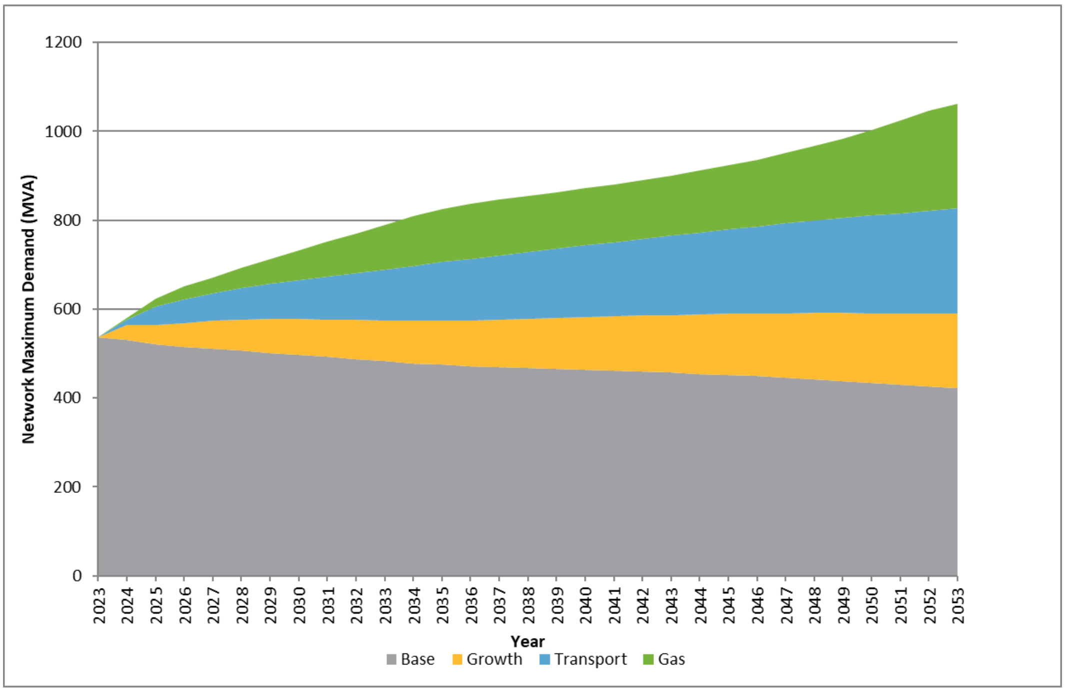


Figure 1-8 Forecast Demand on the Wellington Network 2023-2053

1.5 Network Expenditure

1.5.1 Network Capital Expenditure

WELL's 30-year planning model provides future network investment requirements, and has highlighted two related step changes in investment:

- **Investment to provide new capacity**: The forecast 108% increase in peak demand requires WELL to invest in new capacity. This will require an investment in both traditional new capacity – larger equipment – and new demand management capability (flexibility services) that allows more electricity to be delivered using the existing network.

- **Replacement of WELL's two largest asset fleets**: The zone substation power transformer fleet and the underground cable fleets are coming to the end of their technical lives. In the previous 'business as usual' operating environment, the replacement of these assets started to enter the 10-year AMP planning window for the first time in the 2021 AMP.

Many of the assets due to be replaced are the same assets that require capacity upgrades. The 30-year combined capital expenditure programme rationalises the investment programme so that new assets have both the capacity needed to meet future growth expectations and are replaced before they adversely impact quality. The rationalised capital expenditure programme is smaller than the sum of the two individual programmes.

WELL separates network capital expenditure forecast into five categories:

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

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

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

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

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

WELL is forecasting that in order to deliver the capacity required by the Emissions Reduction Plan, it will need to invest approximately $1.5 billion over the next 10 years, and $2.2 billion over 30 years. This is a significant increase on WELL's historic levels of capital expenditure, and Section 4 of this AMP discusses how that programme will be delivered.

WELL's network capital expenditure, both historical and as forecast for the next ten years, is shown in Figure 1-9.

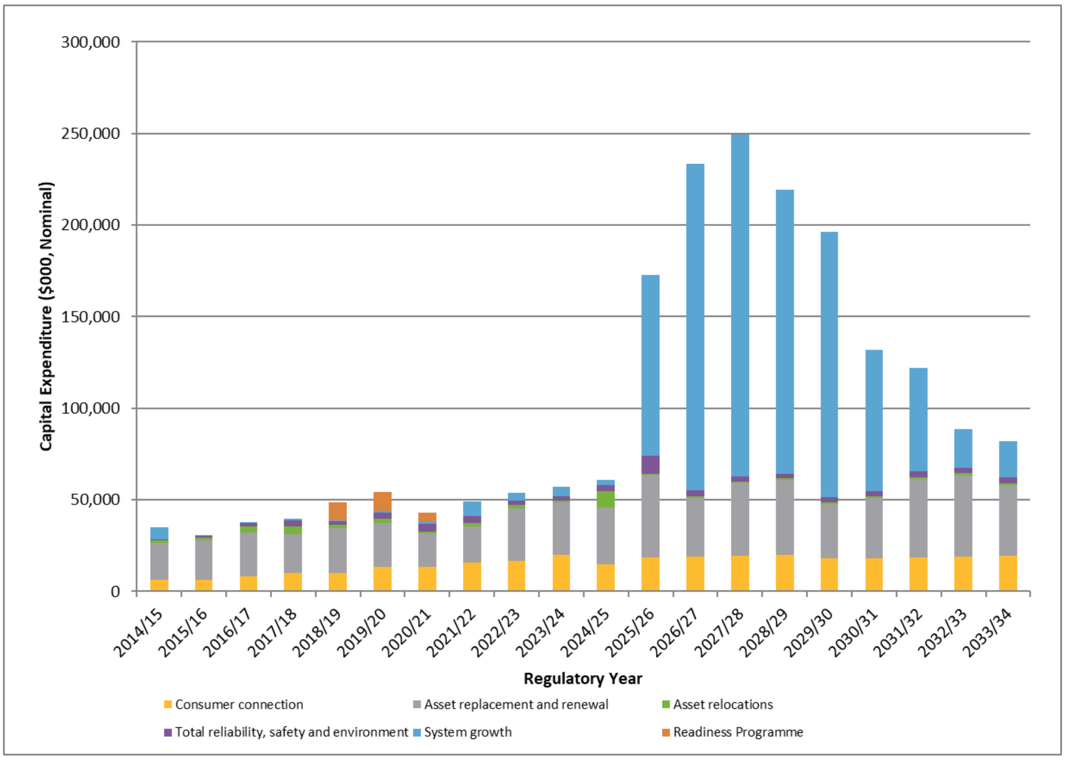


Figure 1-9 Network Capital Expenditure
($K in nominal prices)

1.5.2 Network Operational Expenditure

WELL separates network operational expenditure forecast into four categories:

1. **Service interruptions and emergencies –** includes work that is undertaken in response to faults or third-party incidents and includes equipment repairs following failure or damage.
2. **Vegetation management –** covers planned and reactive vegetation work, through a risk-based programme in addition to cut/trim zone administration.
3. **Routine and corrective maintenance and inspection.** This comprises:
    - Preventative Maintenance works – includes routine inspections and maintenance, condition assessment and servicing work undertaken on the network. The results of planned inspections and maintenance drive corrective maintenance or renewal activities;
    - Corrective maintenance works - includes work undertaken in response to defects raised from the planned inspection and maintenance activities; and
    - Value added - covers customer services such as cable mark outs, standover provisions for third-party contractors, and provision of asset plans for the 'B4U Dig' programme, to prevent third-party damage to underground assets.
4. **Asset replacement and renewal -** includes repairs and replacements that do not meet the requirements for capitalisation.

The network operational expenditure, both historical and forecast, is shown in Figure 1-10.

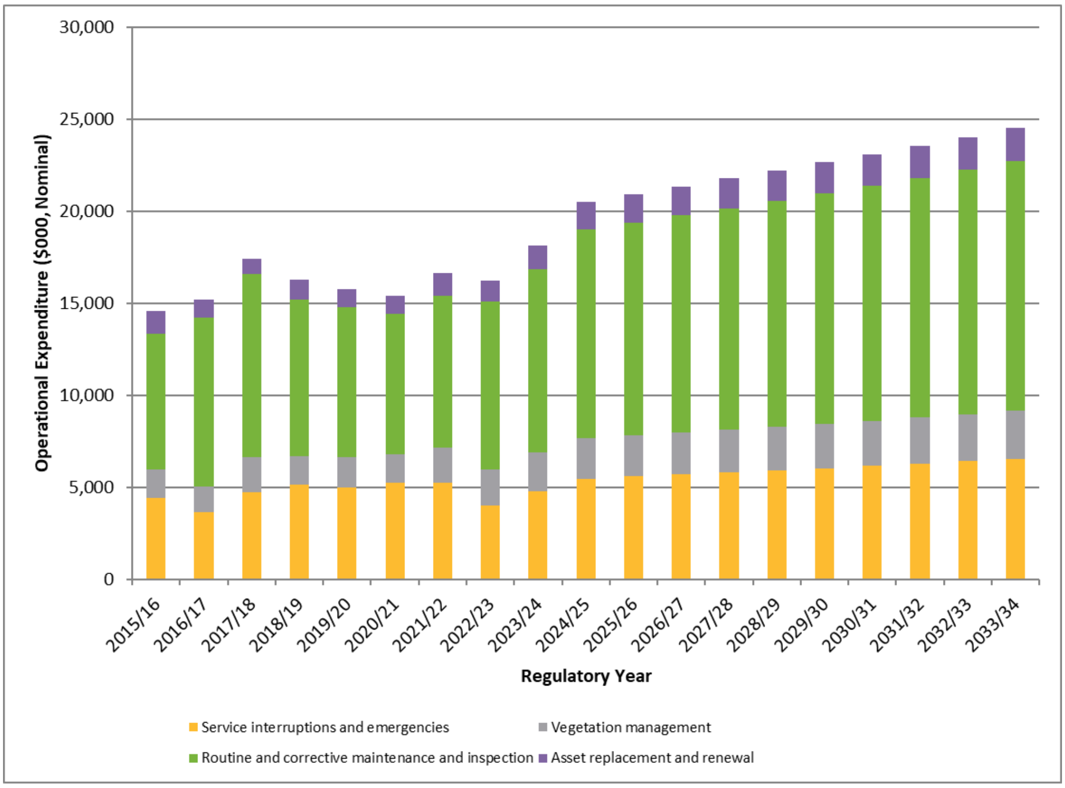


Figure 1-10 Network Operational Expenditure ($K in nominal prices)

1.6 WELL's Capability to Deliver

Delivering the infrastructure required to support the ERP requires a step change in resourcing compared to that which has been required during recent years. To manage the early stage of decarbonisation where the workflow of new projects is not consistent WELL has met this resourcing challenge by engaging an engineering consultancy to provide a Project Management Office (PMO) function. Having an external PMO to call on allows WELL to flex its resourcing as required to support large projects.

The New Zealand electricity industry is suffering from an ageing workforce and global competition resulting in a shortage of trained workers. It is essential that the industry invests in attracting, training, and retaining workers, in order to be able to meet these challenges. To this end, WELL is currently training three graduate engineers on a rotation programme that covers all aspects of the business' operation, including spending time in the field with contractors, and four trainee network controllers.

WELL is engaging with its field service contractors to ensure that they retain sufficient capability to deliver the work plan. Since 2021 WELL has approved two additional contracting service providers to work on the network, to help ensure that WELL retains access to a sufficient field workforce to deliver the plan.

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

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 (amended in July 2023). It describes WELL's long-term investment plans for the planning period from 1 April 2024 to 31 March 2034.

The document was approved for disclosure by the WELL Board of Directors on 28 March 2024.

2.1 Purpose of the AMP

The purpose of this AMP is to:

- Be the primary document for communicating WELL's asset management practices and planning processes to stakeholders;
- Describe how stakeholder interests are considered and integrated into business planning processes to achieve an optimum balance between the levels of service, price/quality positions, and cost-effective investment; and
- Illustrate the interaction between this AMP, WELL's mission "*to own and operate a sustainably profitable electricity distribution business which provides a safe, reliable, cost effective and high quality delivery system to our customers*", and its asset management objective *"to optimise the whole-of-life costs and the performance of the distribution assets to deliver a safe, cost effective, high quality service".*

WELL's asset management practices summarised in this AMP inform WELL's business planning processes including its annual Business Plan and Budget.

2.2 Structure of this Document

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

- **Overview and Approach** which provides an overview of WELL and the approach taken to asset management;
- **Performance Targets and Levels of Service** which provides an overview of the various safety, customer and reliability targets that WELL is measured against and WELL's performance against those targets; and
- **10-Year Investment Plan** which describes WELL's assets, associated strategies, and investment profile over the planning period to meet the defined service levels.

Figure 2-1 illustrates the structure of this AMP.

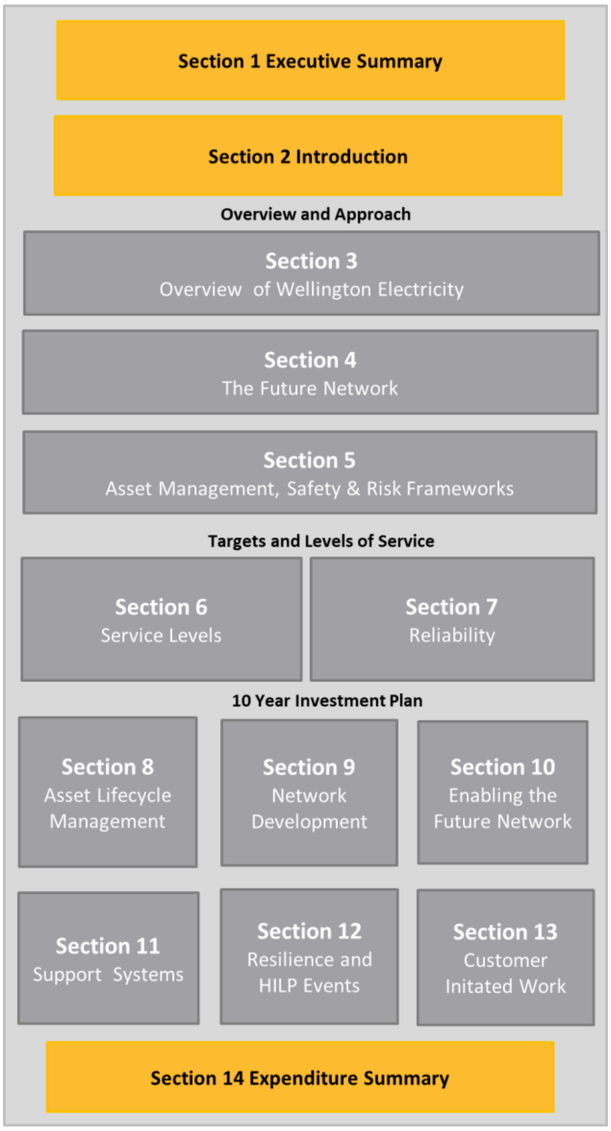


Figure 2-1 Structure of the 2024 AMP

2.3 Formats used in this AMP

The following formats are adopted in this AMP:

- Financial values are in constant price 2024 New Zealand dollars, except where otherwise stated;
- Calendar years are referenced as the year e.g. 2024. 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. 2024/25;
- All asset data expressed in figures, tables, and graphs is at 30 September 2023 unless otherwise stated; and
- All asset quantities or lengths are quoted at the operating voltage rather than at the design voltage. For example, WELL has 8.7 km of 110 kV cable operating at 33 kV. The length of these cables is incorporated into the statistics for the 33 kV cable lengths and not the 110 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;
- Government policy resulting from the Emissions Reduction Plan, leading to the electrification of fossil fuel loads and increased consumer uptake of large DER;
- 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;
- Changes to business strategy driven by internal and external factors; and
- The impact of the regulatory regime.

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

Reduced gas availability and the large-scale transition of vehicle fleets from fossil fuels to electricity under the Emissions Reduction Plan (ERP) will drive a need for increased reinforcement of the network. This investment will need to commence early in the planning period.

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 from 1 April to 31 March.

Section 3
Overview of WELL

3 Overview of WELL

This section provides an overview of the WELL business, its mission and how this translates to the asset management framework. It also describes WELL's corporate structure, governance, asset management accountabilities, the area supplied, description of the network, the stakeholders and the changes that are occurring within the wider operating environment that will impact 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 customers, accounting for the cost/quality trade-off; and
- Operate in the most commercially efficient manner possible within both the current and future regulatory environments.

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

This AMP is supported by WELL's asset management framework, objectives and strategies, which are used to inform its 2024 Business Plan. It takes into account the interests of customers, 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.

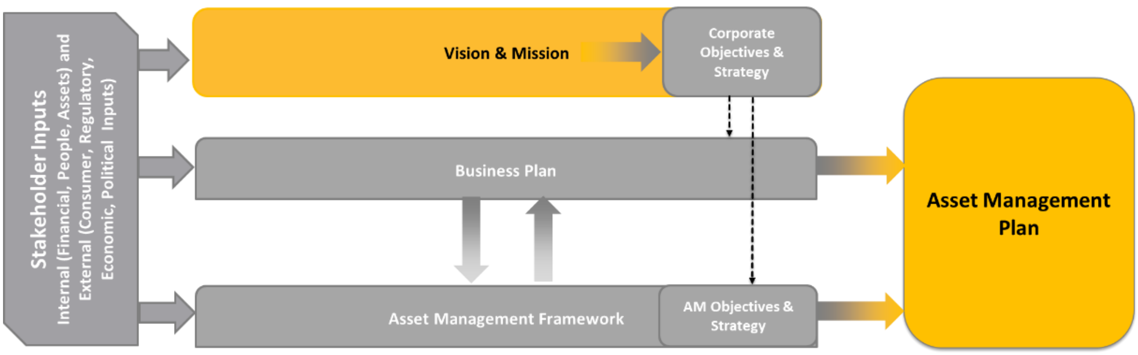


Figure 3-1 Interrelationship between WELL's Mission, the Business Plan, the Asset Management Framework and the AMP

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

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 Limited group of companies, which are listed on the Hong Kong Stock Exchange.

The CK Infrastructure Holdings Limited group has established a strong global presence with investments in the 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, and 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[1]), which meets via conference to discuss the latest developments in new technologies from around the globe.

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

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

3.2.2 Corporate Governance

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

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

3.2.3 Executive and Company Organisation Structure

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

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

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

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

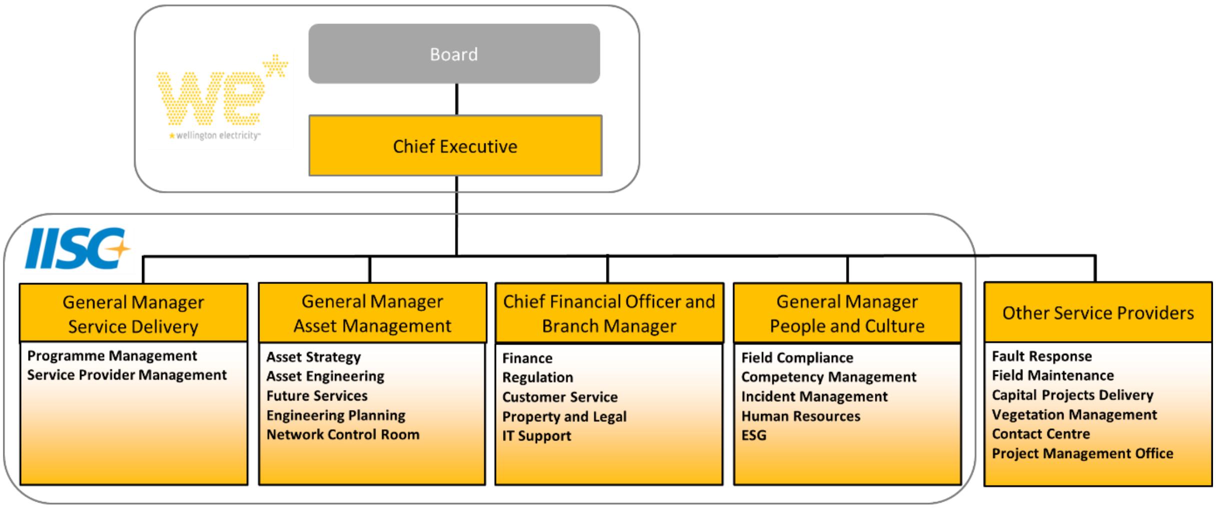


Figure 3-2 WELL Organisation Structure

3.2.4 Financial Oversight, Capital Expenditure Evaluation and Review

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

3.2.4.1 Major Project Financial Approval and Governance

The policies for Authorisation and Payment of Project Expenditure together with the individual DFAs define the procedure for authorisation of WELL's capital expenditure.[2]

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

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

3.2.5 Asset Management Accountability

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

The General Manager – Asset Management is accountable for asset engineering, network planning, standards, project approvals, works prioritisation, 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 the delivery and management of capital and maintenance works and the associated safety, quality and environmental performance of these works. Responsibilities also include the management of outsourced field services contracts.

The Chief Financial Officer is accountable for finance, customer service, regulatory management, legal and property management, and information technology support.

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

The General Manager – People and Culture is accountable for human resources, quality and safety processes, and ESG strategies and targets.

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 Group

The Asset Management team's responsibilities are separated into five areas: asset strategy, asset engineering, asset planning, future services, and network control & operations. 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 and budgets • Quality performance management • Network policies and standards • Technical engineering support • Development and prioritisation of the 3-12 month combined CAPEX and OPEX work plan • Analysis of asset data to inform decision making
Asset Planning	• Safety-by-Design for new builds • Network load forecasting • Reinforcement planning • Large customer connection requests
Asset Strategy	• Strategic network development planning to a 30-year horizon
Future Services	• Development of future network design and operation • Coordination of emerging technology trials
Network Operations	• Network operations and safety • Outage management • Fault response and management • Control Room • Operationalising new technologies onto the network

Table 3-1 Asset Management Team Responsibilities

3.2.5.2 Service Delivery Group

The Service Delivery team's responsibilities are separated into three areas: management of the delivery of capital and maintenance works on the network, and management of the specialist contracts. The responsibilities for each area are described in Table 3-2.

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

Table 3-2 Service Delivery Team Responsibilities

3.2.5.3 Commercial and Finance Group

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

Commercial and Finance Team	Asset Management Responsibilities
Commercial and Regulatory	• Compliance with regulatory requirements
Finance	• Adequate funding of asset management plans
Customer Service	• Accountable for customer relations management including cost-quality surveys
Property and Legal	• Corporate risk management • Management of property and land
Information Technology	• Operational system maintenance and upgrades • Business support systems

Table 3-3 Commercial and Finance Team Responsibilities

3.2.5.4 People and Culture Group

The People and Culture team's responsibilities are described in Table 3-4.

People and Culture Team	Asset Management Responsibilities
QSE	• Quality processes and procedures in place to manage the delivery of asset management plans • Adherence to Health & Safety and Environmental legislation
Human Resources	• The capability of people to deliver Asset Management functions
ESG	• Implementation of corporate ESG strategy • Delivery of agreed ESG targets

Table 3-4 People and Culture Team Responsibilities

3.2.5.5 Other Service Providers

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

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

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

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

The roles and services 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 the infrastructure to support the distribution of electricity to approximately 175,000 customers in its network area, represented by the yellow-shaded area in Figure 3-3. The area encompasses the Wellington Central Business District (CBD), the large urban residential areas of Wellington City, Porirua, Lower Hutt and Upper Hutt, interspersed with pockets of commercial and light industrial load, and the surrounding rural areas. The area has few large industrial and agricultural loads.

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

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

The three areas which are used for planning purposes are:

- **Southern,** defined as the area supplied by Wilton, Central Park and Kaiwharawhara Grid Exit Points (GXPs);
- **Northwestern,** defined as the area supplied by Takapu Road and Pauatahanui GXPs; and
- **Northeastern,** defined as the area supplied by Upper Hutt, Haywards, Melling and Gracefield GXPs.

The network configuration for each of the three areas is described further in Section 3.4.

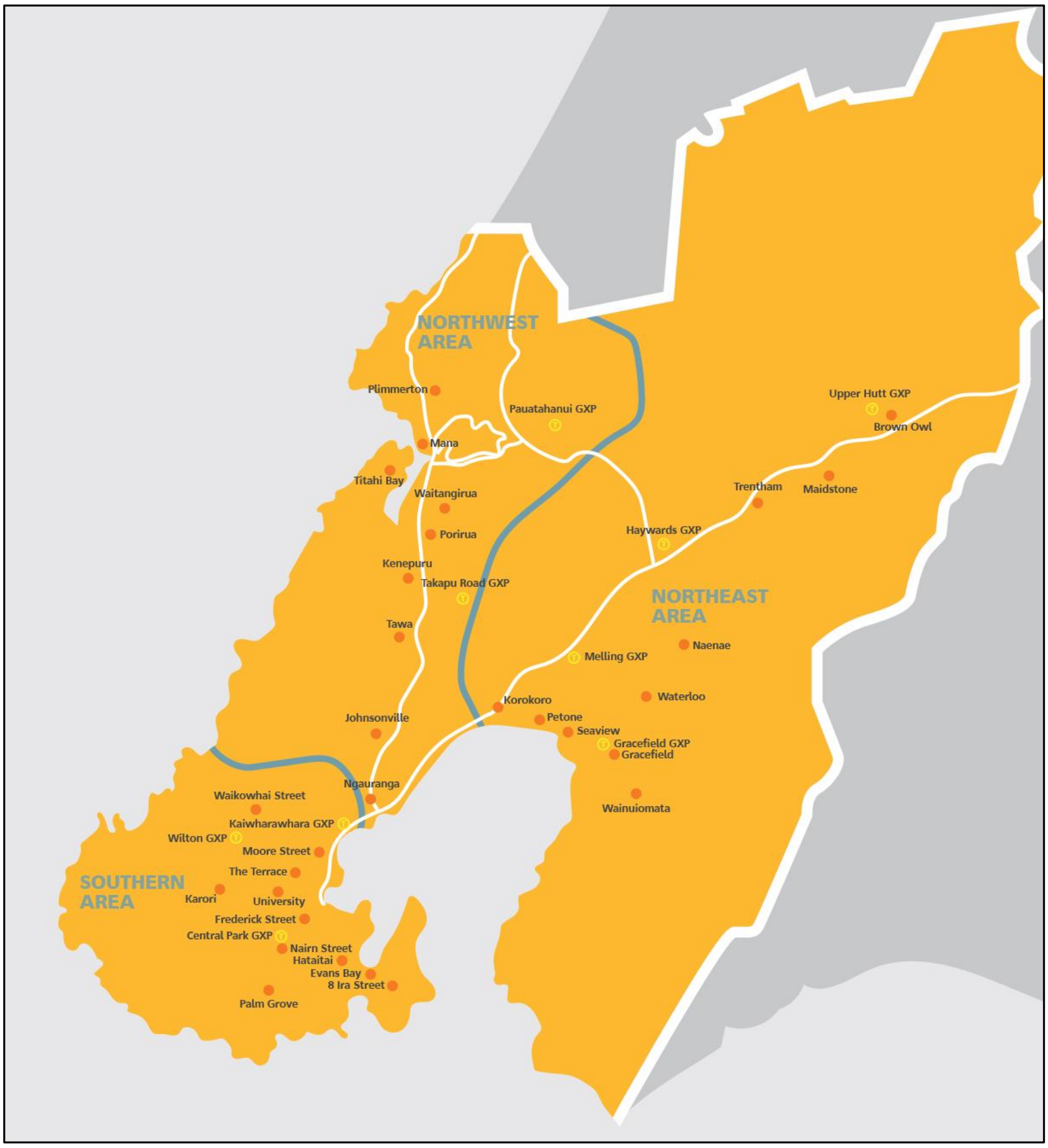


Figure 3-3 WELL Network Area

3.4 The Network

The total system length of WELL's network (excluding streetlight circuits) is 4,818 km, 64% of which is underground. The network is supplied from Transpower's national transmission grid through nine Grid Exit Points (GXPs). Central Park, Haywards and Melling GXPs supply the network at both 33 kV and 11 kV, and Kaiwharawhara supplies at 11 kV only. The remaining GXPs (Gracefield, Pauatahanui, Takapu Rd, Upper Hutt and Wilton) all supply the network at 33 kV only.

The 33 kV subtransmission system distributes the supply from the Transpower GXPs to 27 zone substations at the N-1[3] 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 the Takapu Road branch to supply four transformers (two at each substation). All 33 kV circuits supplying zone substations in the Southern area are underground while those in the Northwestern and Northeastern areas are a combination of overhead and underground. The total length of the 33 kV system is 195 km, of which 138 km is underground. A single-line diagram of the subtransmission network is included in Appendix G.[4]

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. These substations are connected by an 11 kV tie cable and as a result, they operate as a single N-1 substation with a geographic separation of 1.5 km.

The zone substations in turn supply the 11 kV distribution system which distributes electricity directly to the larger customers and to 4,558 distribution transformers located in commercial buildings, industrial sites, kiosks, berm-side, and on overhead poles. The total length of the 11 kV system is approximately 1,807 km, of which 67% is underground. 71% of the 11 kV feeders in the Wellington CBD[5] 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 customers are fed from the distribution substations via the low voltage (LV) distribution network. The total LV network length is approximately 2,860 km, of which 62% is underground. An additional 1,967 km of LV lines and cables are dedicated to providing street lighting services.

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

3.4.1 Southern Area

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

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[3] 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.

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

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

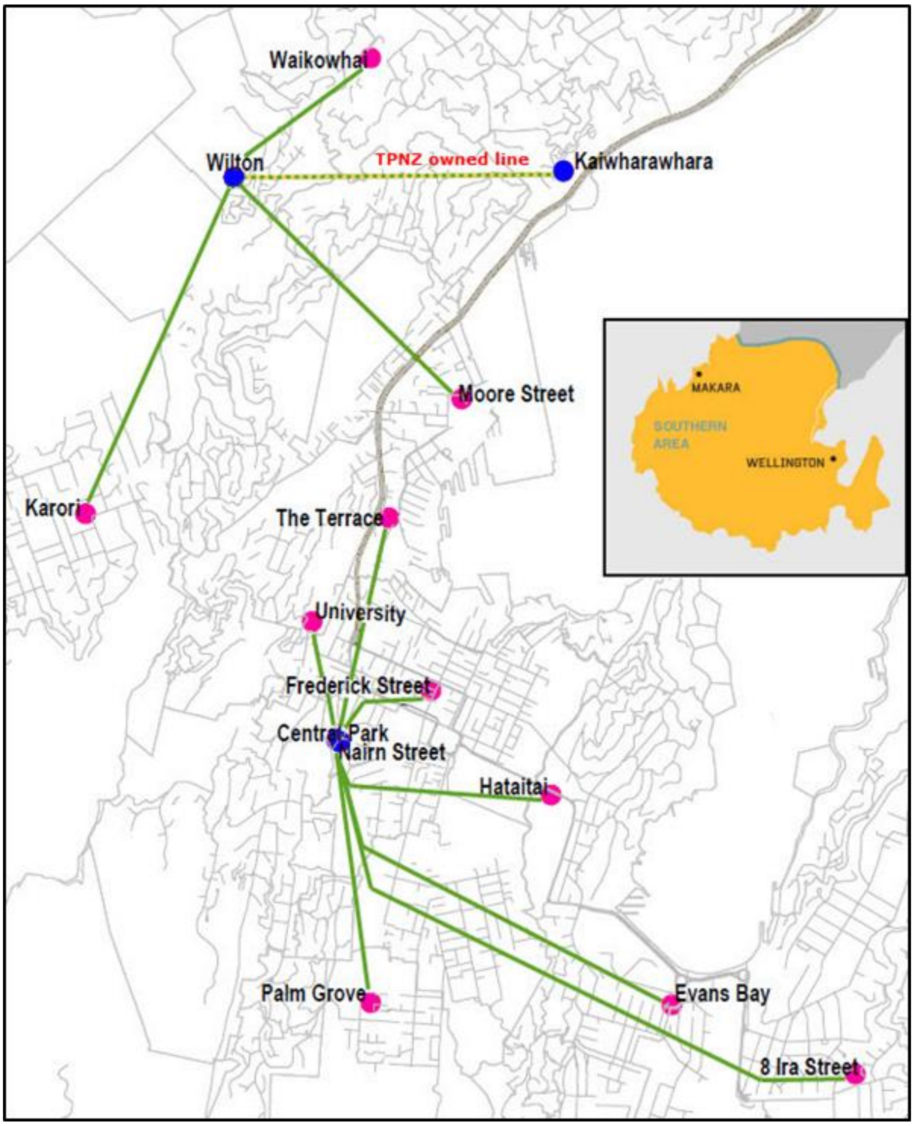

Figure 3-4 Wellington Southern Area Subtransmission Network

3.4.1.1 Central Park

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

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

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

3.4.1.2 Wilton

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

3.4.1.3 Kaiwharawhara

Kaiwharawhara is supplied by two 110 kV circuits from Wilton GXP and has two 38 MVA 110/11 kV transformers in service. WELL takes an 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)	Maximum Demand – 2022 (MVA)	Firm Capacity[6] (summer/winter MVA)	Volumes – 2023 (GWh)	ICP Count
Central Park 33 kV	33	132	217/223	644	42,528
Central Park 11 kV	11	21	30/30	89	7,275
Wilton 33 kV	33	39	103/110	-24[7]	12,786
Kaiwharawhara 11 kV	11	28	38/38	132	5,594
Total				**841**	**68,183**

Table 3-5 Summary of Southern Area GXPs

3.4.2 Northwestern Area

The Northwestern Area network is supplied from the Pauatahanui and Takapu Road GXPs, which supply Porirua City and the Tawa, Johnsonville, and Ngauranga areas of Wellington City. Figure 3-5 illustrates the Northwestern Area GXP and subtransmission network configuration.

[6] Firm Capacity is the N-1 transformer capacity.

[7] This includes 228 GWh injected by Mill Creek Generation

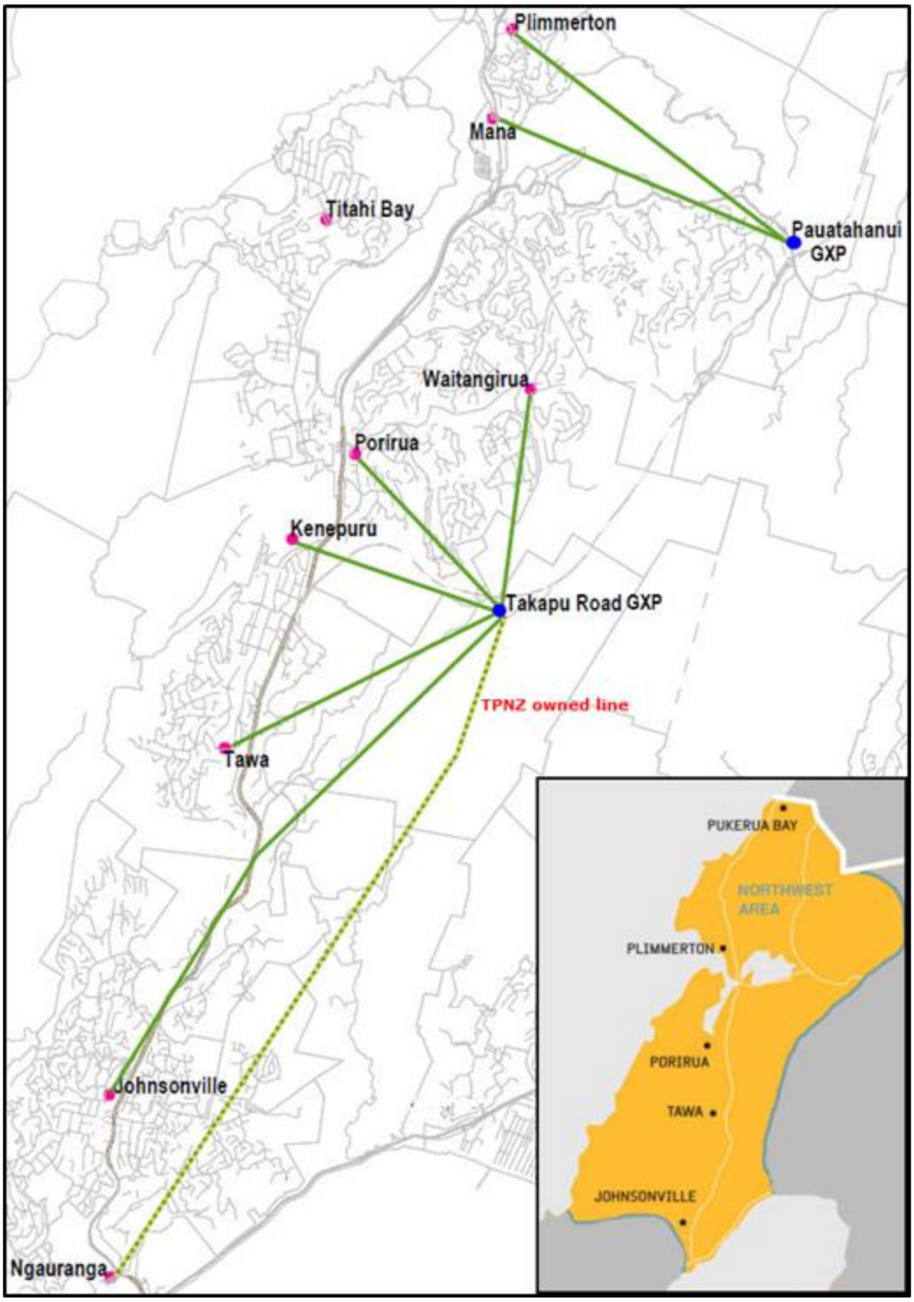

Figure 3-5 Wellington Northwestern Area Subtransmission Network

3.4.2.1 Pauatahanui

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

3.4.2.2 Takapu Road

Transpower's Takapu Road GXP comprises two parallel 110/33 kV transformers nominally rated at 90 MVA each supplying their 33 kV indoor bus. Takapu Road GXP supplies six WELL zone substations at Waitangirua, Porirua, Tawa, Kenepuru, Ngauranga and Johnsonville, each via double 33 kV circuits. These circuits leave the GXP as overhead lines across rural land and become underground cables at the urban boundary. The circuits from Takapu Road to Ngauranga zone substation are Transpower-owned lines rated to 110 kV and operated at 33 kV.

3.4.2.3 Northwestern Summary

Supply Point	Connection Voltage (kV)	Maximum Demand – 2022 (MVA)	Firm Capacity (summer/winter MVA)	Volumes – 2023 (GWh)	ICP Count
Pauatahanui 33 kV	33	18	22/24	70	7,132
Takapu Rd 33 kV	33	92	111/116	425	34,391
Total				**495**	**41,523**

Table 3-6 Summary of Northwestern Area GXPs

3.4.3 Northeastern Area

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

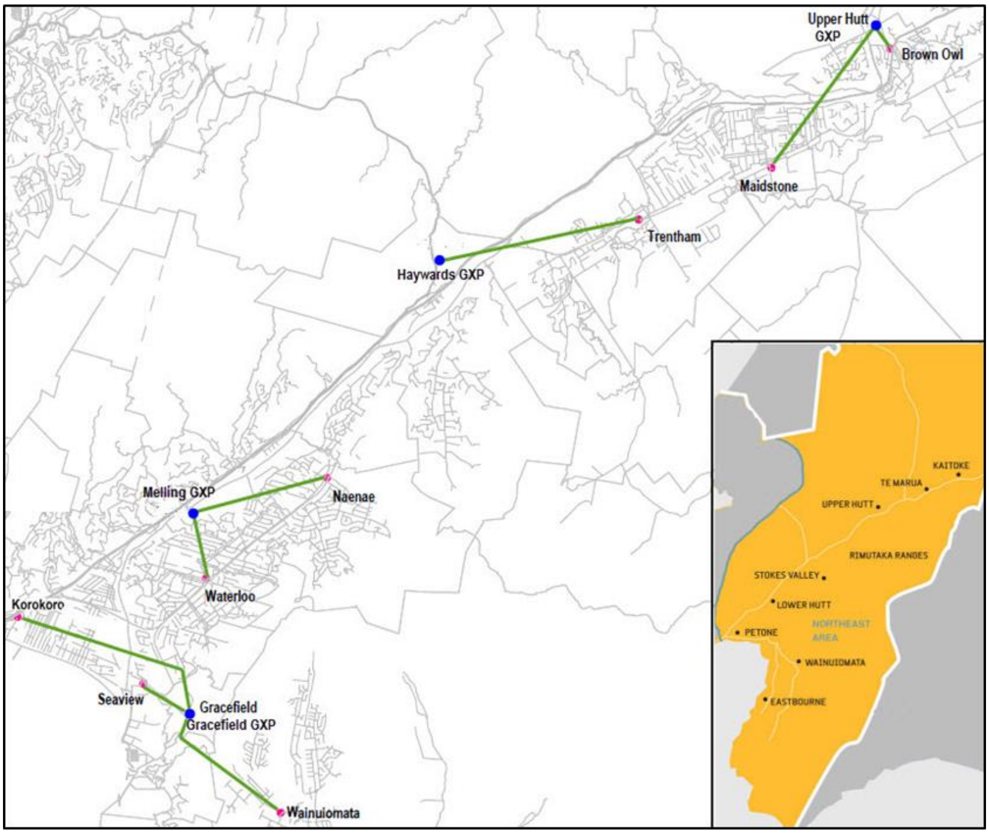

Figure 3-6 Wellington Northeastern Area Subtransmission Network

3.4.3.1 Upper Hutt

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

3.4.3.2 Haywards

Transpower's Haywards GXP comprises two parallel 110/33/11 kV transformers nominally rated at 60/30/30 MVA. WELL takes supply to two 33 kV circuits that supply the Trentham zone substation. Haywards also includes a Transpower 11 kV switchboard, from which WELL takes supply to eight 11 kV feeders.

3.4.3.3 Melling

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

3.4.3.4 Gracefield

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

3.4.3.5 Northeastern Summary

Supply Point	Connection Voltage (kV)	Maximum Demand – 2022 (MVA)	Firm Capacity (summer/winter MVA)	Volumes – 2023 (GWh)	ICP Count
Gracefield 33 kV	33	59	76/80	279	19,808
Haywards 33 kV	33	17	25/25	76	6,087
Melling 33 kV	33	32	64/65	142	12,501
Upper Hutt 33 kV	33	30	51/53	139	11,253
Haywards 11 kV	11	16	30/30	72	6,958
Melling 11 kV	11	24	32/34	110	8,078
Total				**818**	**64,685**

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 3,328 installations of PV with 15,900 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. 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.

3.4.5 Embedded Distribution Networks

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

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

3.5 Regional Demand and Customer Mix

In 2023/24 WELL's network is forecast to deliver 2,315 GWh to customers around the region. The network maximum demand during winter 2023 was 560 MW. Figure 3-7 illustrates the historic trend in volume and maximum demand.

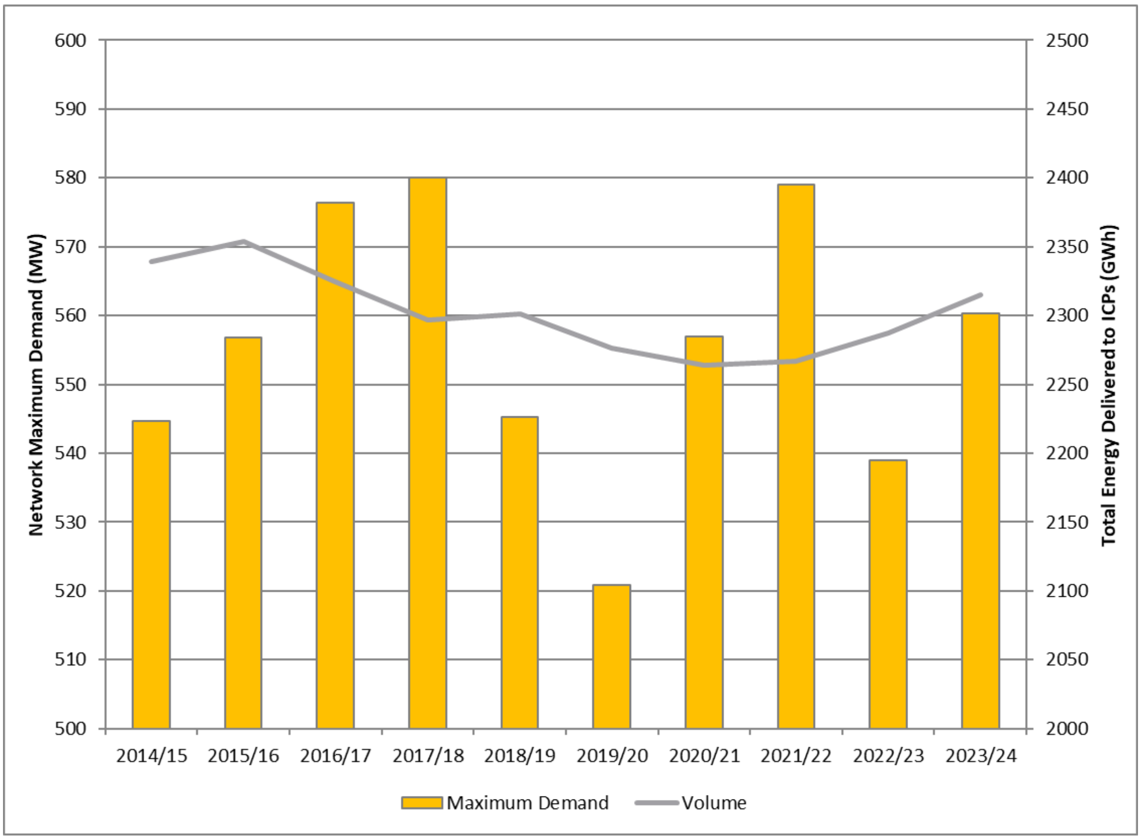

Figure 3-7 Maximum Demand and Energy Injected

On the Wellington network, the period of maximum demand occurs in winter when household heating is at its highest. The maximum demand recorded in any particular year is therefore highly dependent on the nature of the coldest winter weekday – the colder and wetter the day, the higher the maximum demand on the network will be during the evening peak. This dependency on weather creates a significant variation in maximum demand from year to year, with there being no discernible underlying trend over the last 10 years.

Volume figures are independent of maximum demand figures. Whereas maximum demand is set by the weather on the worst day of the year, volume is generally driven by whether the year as a whole is milder or colder than average.

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

Customer Type	ICP Count
Residential	158,216
Large Commercial	515
Medium Commercial	471
Small Commercial	15,055
Large Industrial	39
Small Industrial	508
Unmetered	857
Individual Contracts	17
Total	**175,678**

Table 3-8 WELL's Customer Mix as at February 2024

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

- Parliament and government agencies;
- Hospitals, emergency services, and civil defence;
- Council infrastructure such as water and wastewater pumping stations and street lighting;
- Major infrastructure providers such as Waka Kotahi, Wellington International Airport, and CentrePort;
- Large education institutions such as Victoria University of Wellington, Massey University, Whitireia and WelTec;
- Network security sensitive customers such as the stock exchange, Wētā FX, Datacom, and Department of Corrections.

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

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

Customers' 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:

- Customers and the Community at Large;
- Iwi;
- 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 Customers and the Community at Large

Customers' interests are identified through direct feedback (surveys, queries and complaints) and community engagement. 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 customer engagement initiatives.

WELL uses community meetings, its website and mobile application, public disclosure documents, newspapers, and radio advertising to communicate with the public.

WELL engages with communities in the new technology space such as recent EV trial projects. One trial used half-hourly metering data to measure the size and timing of electricity demand of both a group of EV-owning households and a control group of non-EV-owning households. 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 the time-of-use tariffs that WELL has since implemented.

WELL continues to operate outage reporting applications on both web and mobile-device platforms. The applications provide information on the location and forecast restoration times for unplanned outages. Improving the customer experience by improving the accuracy of published estimated restoration times is a constant focus for WELL and its contractors. WELL is currently trialling publishing planned outages on its web and mobile platforms.

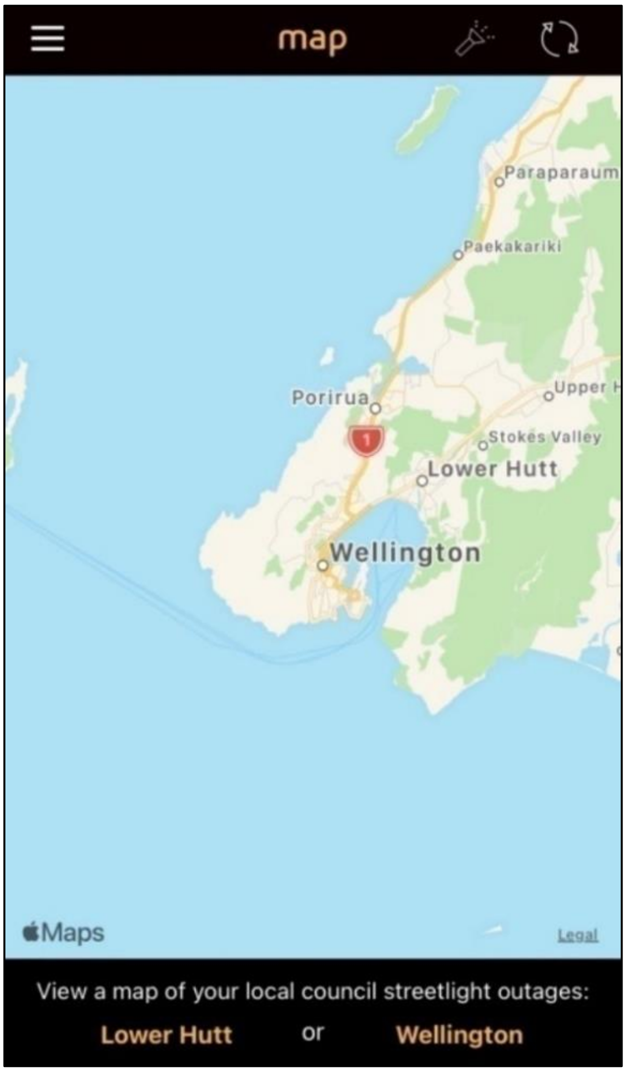

Figure 3-8 WELL's Web-based Application

3.6.1.2 Iwi

WELL is committed to strengthening its relationships with local iwi. WELL is striving to communicate in an open and timely manner and to ensure there is an understanding of each other's priorities and expectations. Early engagement around projects will help provide positive outcomes.

3.6.1.3 Retailers

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

Customer supply quality interests are accounted for through meeting the regulatory quality targets defined in the Commission's price-quality path and the service levels detailed in Section 5.

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.

3.6.1.4 Regulators

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

WorkSafe 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 Persons Conducting a Business or Undertaking (PCBUs). WELL has an audited Public Safety Management System (PSMS) that covers the management of assets installed in public areas to ensure that they do not pose a risk to public safety.

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

3.6.1.5 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 requires 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 the implementation of operational standards and procedures, appropriate investment in the network, and regular meetings.

3.6.1.6 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 customer 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 customers 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 highlighted the importance of having a resilient electricity network. This work is described further in Section 12.

Central and local government will also have an interest in WELL's progress in supporting their decarbonisation initiatives. This work is described in Section 4 and Section 10.

3.6.1.7 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.

As a lifeline utility (an essential service), WELL also works closely with the Wellington Lifelines Group. The purpose of the Wellington Lifelines Group is to ensure that lifeline utilities provide continuity of operation where their service supports essential emergency response activities. Participation in this working group is described in Section 11.

3.6.1.8 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.

3.6.1.9 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.

3.6.1.10 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 customer complaints. WELL’s Use of System Agreements provides a dispute resolution process for managing conflict with retailers.

3.7 Operating Environment

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

3.7.1 Legislative and Regulatory Environment

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

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

Building on its good safety and environmental record, and consistent with the requirements of the HSW Act 2015 as well as the company’s drive for continual improvement, WELL continues to focus on potential safety and environmental risk at the early stages of a project. Risk assessments are conducted with contractors prior to the project being awarded, with continual monitoring throughout the project lifecycle of potential changes in risk. The cost and time implications of this increased focus are factored into project budgets and schedules. WELL also reviews incidents with its service providers on a weekly basis and monitors the effectiveness of controls that are being put in place. Emphasis is placed on ensuring that engineering controls are prioritised ahead of process and administration controls.

The main aspects of 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 in the management of the interface boundary with all principals that do work with WELL.

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

3.7.1.2 Price Quality Compliance

WELL is subject to price and quality control contained within Part 4 of the Commerce Act 1986. From 1 April 2018, WELL was on a CPP for its earthquake readiness programme, which ran until 31 March 2021. WELL returned to the Default Price Path (DPP) on 1 April 2021.

3.7.1.3 Information Disclosure

WELL is subject to a range of annual public information disclosure requirements. To ensure accurate preparation and reporting of information, WELL's business processes and information systems are aligned to the Information Disclosure Determination 2012 to ensure that information is accurate and available in the prescribed form.

3.7.1.4 Default Distributor Agreements

Retailers contract with Electricity Distribution Businesses (EDBs) for the supply of distribution services. WELL has a Default Distribution Agreement (DDA) with each retailer. The DDA agreement terms are provided in the Electricity Code.

3.7.1.5 Pricing Roadmap

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

3.7.1.6 Government Policy - Major Infrastructure Projects

Major projects driven by government policy have an impact on WELL's network. The Government's Emissions Reduction Plan includes a number of workstreams that would impact the network, including:

- Electrification of New Zealand's transport fleet;
- Electrification of process heat in manufacturing; and
- The transition from gas to electricity.

These changes could significantly impact the loading and operation of the electricity distribution network, which, if not well managed, could slow down the decarbonisation programs or increase costs. WELL's view is that by collaborating with other industry stakeholders, the programmes can be supported at an optimal cost while maintaining a safe, secure, and reliable distribution network for all customers.

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 comments 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.

3.7.2 The Changing Technology Environment

There continues to be much interest around distributed energy resources (DER) and how these will impact transmission and distribution networks, metering, central generation, and retailers. This new technology could also impact customers, with new markets developing for customers if they choose for their assets to be used for demand management.

The growth of new technologies in the energy storage and market trading environments has a significant effect on the development of smarter electrical networks, and the ability of WELL to influence energy consumption. 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 the electricity sector. This includes (but is not limited to) monitoring the uptake of commercial and residential solar panels (Photovoltaics or PVs) and energy storage systems, the increasing penetration of EVs in New Zealand's vehicle fleet, and the applicability and use of technology for network monitoring, design, and operation. Technology will have an increasingly significant impact on customer behaviour as EVs, PVs, and battery storage become more affordable.

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

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

- **Mandatory registration:** Require customers who want to install new technology to register their devices to a demand management platform. This will ensure that the installation of the new technology complies with the standards of the network for two-way power flows;

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

- **Low voltage monitoring:** Improve the monitoring of the network particularly LV with DERs where current monitoring is inadequate and where changes are most likely to be felt;

- **Support with efficient prices:** Introduce efficient price signals that reflect the benefits new technology can provide, while ensuring that this does not result in cross-subsidisation from customers who are unable to install their own DER;

- **Consumption and power quality data:** Consumption and power quality data are needed to support the operation of the low voltage network with an increasing prevalence of DER. The industry needs to decide what data is needed, and how to collect, store, protect, and utilise the information; and

- **Appropriate funding:** Ensure the regulatory framework provides the allowances required to develop and implement these changes, and to purchase data and demand response services.

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

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

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

3.7.2.1 Electric Vehicles

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

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

To support the swift adoption of EVs, WELL ran EV Connect, an industry-wide work programme that focuses on how more energy can be delivered through the existing network. The purpose of EV Connect is to support EV adoption while maintaining network security. One of the outcomes of the programme has been the delivery of an industry roadmap of the actions needed for distribution networks to accommodate the uptake of EVs. EV Connect is discussed in detail in Section 10.

WELL also supports the electrification of public transport as a significant means of reducing carbon emissions. WELL is supporting the regional and city councils to deliver new electric public transport services in Wellington.

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 regularly reviews which regulatory model is most appropriate, balancing the low-cost simplicity of the DPP against the ability to fund large capital programmes under a CPP.

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

WELL is continuing to manage its financial performance in a prudent manner, ensuring expenditure is targeted at the highest priorities and maintaining the quality of supply under the price-quality framework. WELL continues to access global debt capital markets to ensure it has appropriate financing facilities available to meet the investment plans outlined in this AMP.

Section 4

The Future Network

4 The Future Network

WELL has modelled the impact of New Zealand's Emissions Reduction Plan (ERP) and has incorporated the demand impact and service changes into its AMP planning processes. The decarbonisation programme has created significant changes to the AMP processes and forecast disclosures. This chapter provides our 30-year view, aligning with the ERP delivery timetable, of the Wellington network's future demand and investment profiles. This provides context to the more detailed 10-year AMP planning window, outlining the overarching drivers and reasons behind the changes to this year's AMP disclosures.

For the last decade, the Wellington distribution network has operated under a 'business as usual' operating environment with modest new connections growth and a steady asset replacement programme. WELL has been funded by the low-cost Default Price Path (DPP) which is designed for this type of stable operating environment. WELL has been able to keep prices low by using demand response tools to manage Wellington's low growth, allowing WELL to operate with minimal capacity headroom and avoiding the need for expensive capacity increases.

In June 2021, the Climate Change Commission (CCC) published its Final Advice to Government on how New Zealand can become carbon neutral by 2050.[8] In May 2022 the Government finalised its plans in its ERP.[9] The plan includes decarbonisation programmes to electrify transportation, transition away from using fossil gas (and potentially to electricity), and electrify some manufacturing process heat. These changes will increase electricity consumption and increase New Zealand's reliance on electricity.

Over the last four years, WELL has been participating in various government consultations to help develop the decarbonisation programme. WELL has also been developing its view of the impact the decarbonisation programmes will have on electricity demand in the Wellington region. The programme will increase electricity demand, with WELL's initial modelling forecasting demand to increase by 98% over the next 30 years. While New Zealand's decarbonisation programme is a primary driver of the increase, WELL is also expecting population growth and new connections to increase at a rate faster than what we have seen over the past decade. This is partly due to the expected response to Wellington's housing shortage.

How customers use the distribution network is also changing. New consumer products will allow homes to generate, store, and export energy from behind the meter. Where previously the distribution network was used to deliver electricity to consumers using a one-way power flow, the future network will need to facilitate two-way power flows so that electricity can also be distributed from a consumer's premises to other consumers or agents.

WELL is also about to start the replacement of two of its largest asset fleets. The zone substation power transformer fleet and the underground cable fleets are coming to the end of their useful lives and will need replacing. In the previous 'business as usual' operating environment, the replacement of these assets started to enter the 10-year AMP planning window for the first time in the 2021 AMP. However, these ageing assets will now need replacing earlier than initially planned due to introduction of ERP-related demand growth. This is economically advantageous as new assets can be sized for the new decarbonisation demand with clear new demand expectations through to 2050 on 45yr life assets.

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[8]https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/evidence/advice-report-DRAFT-1ST-FEB/ADVICE/CCC-ADVICE-TO-GOVT-31-JAN-2021-pdf.pdf, 31 January 2021.

[9] https://environment.govt.nz/what-government-is-doing/areas-of-work/climate-change/emissions-reduction-plan/

The Wellington network now requires a step change in its capacity and capability as New Zealand implements its climate change programmes, consumers demand new distribution services, and the largest asset fleets on the Wellington network come to the end of their useful lives and are replaced. While these work programmes require significant investment in their own right, WELL's modelling shows that combining the three programmes provides opportunities to consolidate the CAPEX programme by replacing ageing assets with technology that can support new services and larger capacity equipment, allowing WELL to deliver the programmes at a cost less than the sum of the individual programmes.

This chapter provides an overview of the drivers of future demand growth, highlighting the impact of the climate change programme, correcting the housing shortage, and meeting long-term population growth. The chapter also presents WELL's initial thinking on how it will build the capability and capacity to deliver the demand increase. Relying on the traditional 'wire solutions' of building more capacity will not allow distribution networks to deliver the demand increase at an affordable price. This chapter presents WELL's delivery strategy of developing market participants to provide flexibility services using customer distributed energy resources (DER) to deliver more electricity using the existing network while building new capacity for the peak demand increase that can't be shifted.

The strategy includes taking a holistic look at household energy costs to ensure that building the new capability and capacity remains affordable: while electricity costs may increase, household energy costs should decrease overall as fossil fuels are replaced with less expensive electricity. Electricity distribution networks will continue to provide consumers with the lowest cost and most reliable means of supplying energy to the household.

Case Study 1 – The Benefits of Scale

The New Zealand electricity network offers an inexpensive and reliable source of energy for households and businesses because its costs are shared between millions of people. Household and business energy costs would be significantly higher and less reliable if individuals or communities had to invest in their own alternative energy sources and the equipment to transport that energy to where it is needed.

Figure 4-1 compares this annualised cost of a household off-grid system with the residential annual power bill for the average New Zealand customer.[10]

Year	Estimated Annualised Off-Grid Cost	Average Annual NZ Household Electricity Bill	Difference ($)	Difference (%)
2023	$4,909	$2,213	$2,696	55%

Figure 4-1 Comparison Between Off-Grid Costs and Average Residential Electricity Bill

WELL estimated off-grid costs as part of its annual pricing setting process to test whether customers would be better off using an alternative to the distribution network. The off-grid solution assumes solar panels and battery array. An LPG connection is included for cooking, space heating, and water heating, to reduce the size of the solar-battery system required by the household. A diesel generator is also included as a backup to the solar-battery system as there will be times during winter when solar-battery systems fall short for non-gas use.

[10] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring/

As customers decarbonise and move more of their energy use to electricity, electricity supply system will become even more diverse. The electricity network will provide customers access to the large-scale renewable generation needed for New Zealand to meet its target of 95% of its energy being renewable. Without access to grid generation (including the hydro lakes) it will be impossible to meet New Zealand's emissions reduction targets (i.e. off-grid solutions rely on fossil fuels and won't have access to the renewable energy needed to decarbonise).

4.1.1 The Benefit to Customers

While the ERP is driving a step change in network investment, it is also providing important new benefits to customers. The majority of those benefits will not all be captured in quality measures and incentives used to regulate EDBs. It is important to recognise all of the benefits of the investments now included in this AMP, that will deliver to customers.

4.1.1.1 Reducing Emissions

New Zealand has a unique opportunity to be able to meet the majority of its energy requirements by adding wind and solar generation to New Zealand's already large hydro and geothermal generation. The electrification of light transportation, some or all gas use and process heat will deliver 30% of New Zealand's emissions reduction target. In 2022 the electricity industry funded an independent study to test different pathways to deliver its part in the ERP. The Boston Consulting Group's 2022 *'The Future is Electric'*[11] outlines a credible pathway to achieving New Zealand's decarbonisation objectives through more renewable generation and the electrification of transport and heating. The report shows that with decisive and early investment, the sector can achieve close to 100% renewable electricity by 2030 and abate 22 million tonnes of CO2-e annually by 2050. Distribution networks will play a central role in delivering the increase in electricity demand and hosting flexibility services that will be needed to assist in maintaining a secure supply.

Customers are already responding to the need to electrify fossil fuel use, implicitly supporting the ERP. Total EV numbers in Wellington have increased by 55% in the last 12 months, and projects are underway to double local electric commuter train frequency and carriage numbers and to electrify public buses.

4.1.1.2 Lowering Household Total Energy Costs

While customer electricity bills will increase as households use more electricity and new electricity infrastructure is built, overall householder energy costs are forecast to decrease as customers use less petrol, diesel, and gas.

The Climate Change Commission's 2021 Advice to Government, ENA's 2022 '*Total Household Energy Costs NZ'*, *'The Future is Electric'*, and WELL's own 2017 EV trial all have shown that electrifying the home and vehicles will mean overall household energy costs will reduce. These studies show the electrification of households' vehicles provides the largest benefits, while the savings from electrifying gas appliances provide modest decreases or a small cost increase.

The Climate Change Commission Draft Advice to Government included modelling of the effect that replacing an ICE vehicle with an EV would have on household energy costs for 2035. The modelling showed that while total electricity costs would increase by 26%, the overall household energy cost would reduce by 32%, as shown in Figure 4-2.

[11] https://www.bcg.com/publications/2022/climate-change-in-new-zealand

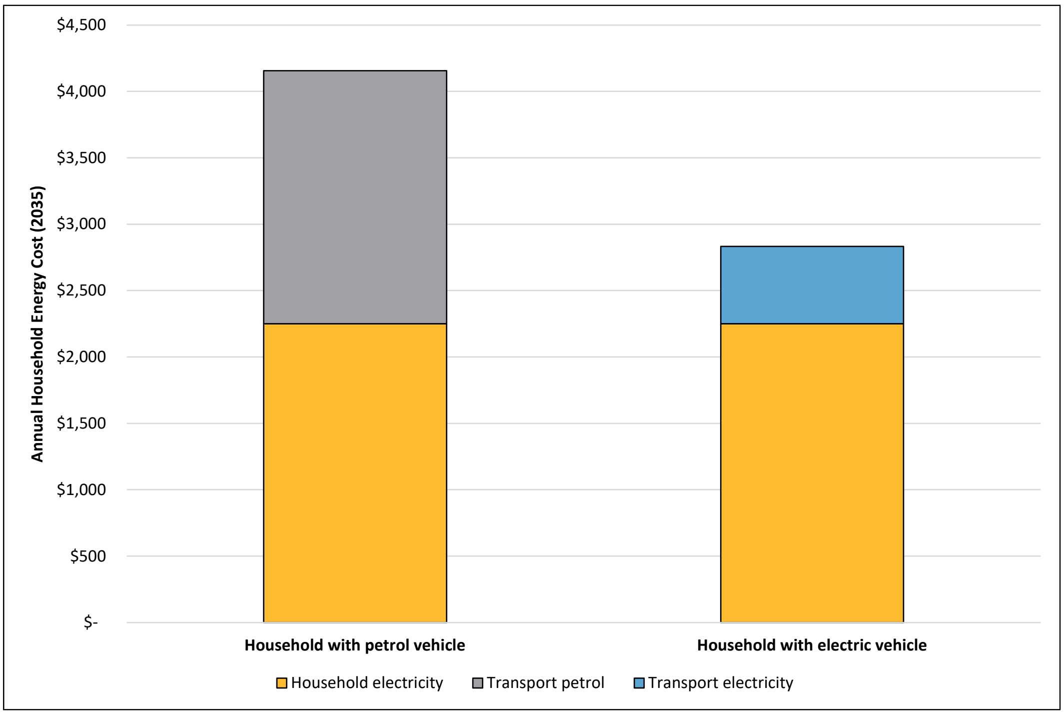

Figure 4-2 Household Financial Benefit of Electric Vehicles (Source: CCC Draft Advice 2021)

These studies have assumed that the upfront cost of purchasing new electric appliances and vehicles can be spread over the life of the new appliances, matching the costs with the benefits. In reality, some households will not be able to afford to purchase new electric appliances, so may not have access to the low energy costs offered by electrification. Appliance affordability will be an important issue to solve. Other governments are considering low or no-interest loans for low-income families, providing all households with access to lower household energy costs and maintaining momentum on their emissions reduction programmes. WELL would support a similar programme in New Zealand.

4.1.1.3 Meeting Changing Customer Expectations

Customers are changing how they want to use distribution services. They are plugging in devices like EV fast chargers that have loads larger than low voltage networks were designed for. Customers are becoming less accepting of poor service quality as they become more reliant on electricity as they shift away from fossil fuels like gas.

Future distribution services will also enable customers to manage their electricity use in new ways. They will be able to balance and optimise their household electricity use by charging their EV battery when electricity is cheap (off-peak) and running the household from the car battery when electricity is more expensive (on-peak). They can provide their own backup to the electricity network using the vehicle battery during an outage.

New smart devices once connected and registered to a service provider, also provide customers with the opportunity to participate in flexibility services – services which will enable the industry to deliver more electricity using the existing network, avoiding expensive network reinforcement and reducing to size of future price increases.

Future distribution services will provide two ways power flows across local networks allowing customers to share and re-distribute electricity stored and generated from their homes. Customers are demanding more from distribution services so they can recognise the full benefits that their new devices can provide.

4.1.2 On-going Development and Refinement of the AMP

This chapter provides a 30-year view (aligning with the ERP delivery timeframe) of the Wellington network's future demand and investment profiles. This provides context to the more detailed 10-year AMP planning window, highlighting the overarching drivers behind the forecasts and the reasons for changes from the previous AMP disclosures. The last section of this chapter summarises the key characteristics of the future network and how it relates to changes in the detailed AMP disclosures.

WELL is making good progress on defining the investment requirements needed to develop the capability and capacity to meet future demand and to provide new distribution services supporting two-way power flows. WELL has developed an initial view of the demand forecast and the capital requirements needed to meet the demand increase. However, the ERP is less than two years old and WELL's forecast models are still being refined and updated as thinking is developed and new experience is incorporated.

New Zealand is also still developing how it will deliver the ERP and there are aspects of the delivery which are still being decided which will have a significant impact on WELL's future investment plans. For example:

- The Government's Gas Transition Plan will outline whether gas use will transition to electricity or another gas source. Reticulated natural gas is used as a fuel in one third of Wellington homes, making the city New Zealand's highest residential gas user, so this decision will have a significant impact on WELL's demand forecast and capacity requirements. However legislation allowing a change in gas pricing so operators receive return of investment will see consumers adopt cheaper options ahead of these gas decisions.

- WELL has identified flexibility services, which industry participants can use connected & registered customer devices to manage electricity use away from peak demand periods, as an important tool to manage energy costs and also delay network reinforcement (peak periods) However, these services are still being developed and their effectiveness is still unknown.

- Distribution networks generally do not have operational visibility of their low voltage networks or where EVs are being charged. Networks still need to develop the capability to understand changes in demand at residential locations that create low-voltage capacity constraints and low-voltage network reinforcement investment requirements.

Readers of AMPs can expect the forecast disclosures to change from year to year as AMP processes are developed, refined, and adjusted. Section 4.3 considers how WELL's internal processes and capability will also have to evolve, which is then reflected in the delivery strategy provided in Section 4.4. Unlike in the past 'Business as Usual' operating environment, EDBs will have to keep adjusting their investment plans to meet changes in uncertain ERP-related demand, to reflect their own evolving understanding of how the services being delivered over their networks are changing, and what new capability is required.

4.2 The Drivers of Change

For the last decade, the Wellington distribution network has operated under a 'business as usual' operating environment with modest new connections growth and a steady asset replacement programme. Previous

AMPs have focused on asset health, maintaining the existing asset fleets, and preserving the existing quality of supply levels. The majority of investments made have been to replace ageing assets as they reach the end of their useful lives. Similarly, the supporting regulatory model has been focused on efficiency, incentivising networks to provide the same level of service at a more efficient price, setting allowances and quality targets based on historic performance, and rewarding cost savings.

In response to modest historic long-term population growth in Wellington of less than 1% per year, and declining electricity use per household due to more efficient appliances, WELL has developed demand management tools to deliver new growth using the existing network. Demand management tools are used to manage congestion by redistributing electricity usage across Wellington's mesh network[12] or to shift electricity use to less congested times using ripple control and cost-reflective prices. This has allowed WELL to meet new growth without needing to build expensive new network capacity, minimising the cost to customers.

Figure 4-3 summarises the focus of WELL's historic investment programme as a proportion of total expenditure. Historic network investment has focused on asset renewals and replacements, connecting new customers, and improving resilience with the three-year earthquake readiness programme from 2019 to 2021. WELL has not needed to make significant investments in new network capacity.

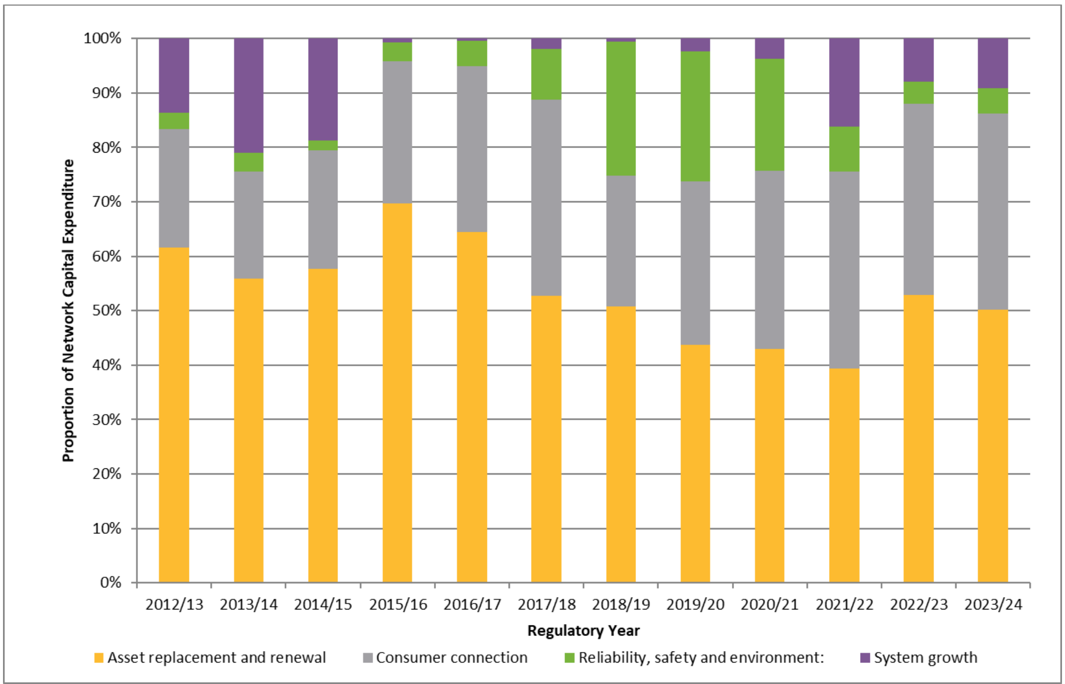

Figure 4-3 WELL's Capital Expenditure Programme 2012/13-2023/24

The focus on efficiency has meant customers on the Wellington network have benefited from low prices and good quality of supply. The benchmarking analysis in Figure 4-4 shows that Wellington customers enjoy one of the lowest distribution prices in New Zealand while receiving one of the most reliable services. In the chart, WELL is the yellow diamond located in the low SAIDI/low-cost quadrant of the chart, with the other EDBs displayed as grey diamonds.

[12] Parts of Wellington's 11 kV network are designed in a mesh pattern which allows the supply of electricity to be redistributed to where it is needed. If a part of the networks is congested, electricity can be supplied from another direction to relieve the congestion.

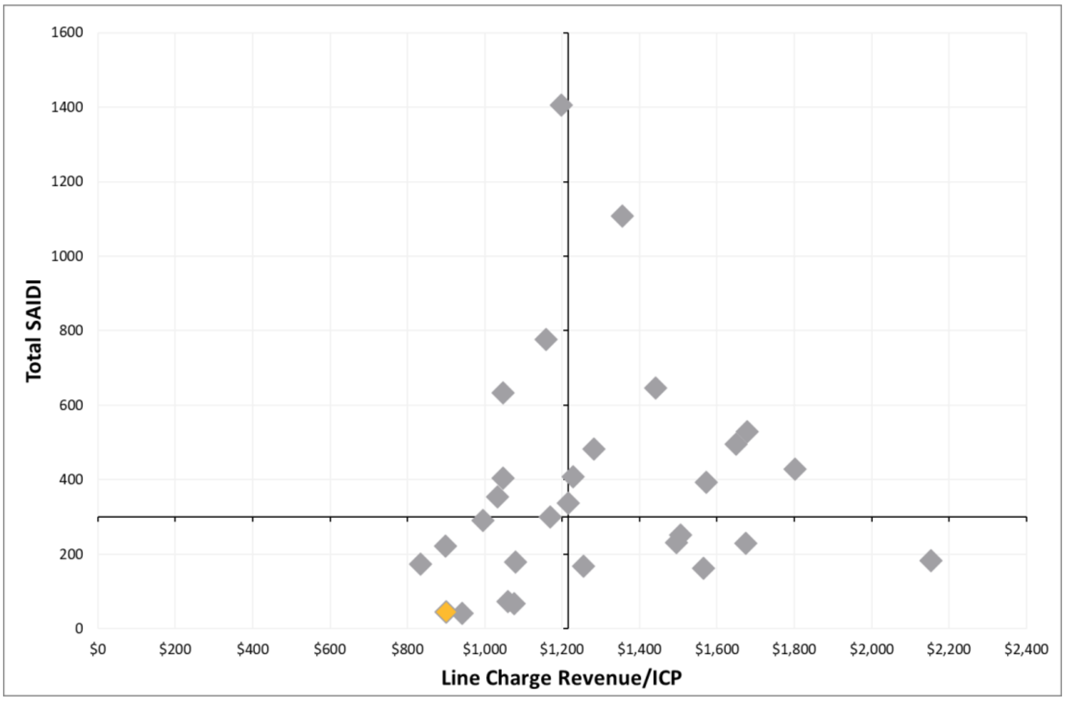

Figure 4-4 Quality vs Price Benchmarking Analysis (2021-2023)[13]

4.2.1 New Zealand Emissions Reduction Programme

Rapid demand growth is forecast on the Wellington network, with peak demand expected to increase by 98% over the next 30 years. Aside from population growth, the primary driver is the ERP, which includes the electrification of transportation and the potential transition from natural gas to other energy sources such as electricity.

While the magnitude of EV- and population-driven peak demand growth by 2050 can be made with a high level of confidence, the demand forecasts for electricity as a gas substitute and the demand offset from flexibility services are less certain. WELL's forecast assumes that electricity will replace fossil gas, but the ERP includes the possibility of natural gas being replaced with renewable gas sources. WELL has also forecast that flexibility services will offset some peak demand, but these services have yet to be developed to the scale needed. Table 4-1 summarises the demand forecast and the key drivers of that demand.

[13] Data sourced from https://www.comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data/information-disclosed-by-electricity-distributors

Growth		Assumption	98th Percentile of Demand (MW)	Total change (%)	Annual change (%)
Current Demand (2023)			**536**	**N/A**	**N/A**
Growth Source	Population Growth	Population Growth + Industrial Growth + Housing Shortage	168	31%	1.0%
	Transport Electrification	Emissions Reduction Programme	237	44%	1.5%
	Transition from Gas	Emissions Reduction Programme	237	44%	1.5%
New Growth			665	N/A	N/A
Total Demand (2053) - Uncontrolled			**1,178**	**120%**	**4.0%**
Demand Management		Introduction of Flexibility Services	-115	-21%	-0.7%
Total Demand (2053) - Controlled			**1,063**	**98%**	**3.3%**

Table 4-1 WELL's Demand Growth Forecast

Figure 4-5 shows this forecast peak demand growth profile to 2053. For clarity, the impacts of energy efficiency and flexibility services have been included in the baseline figure.

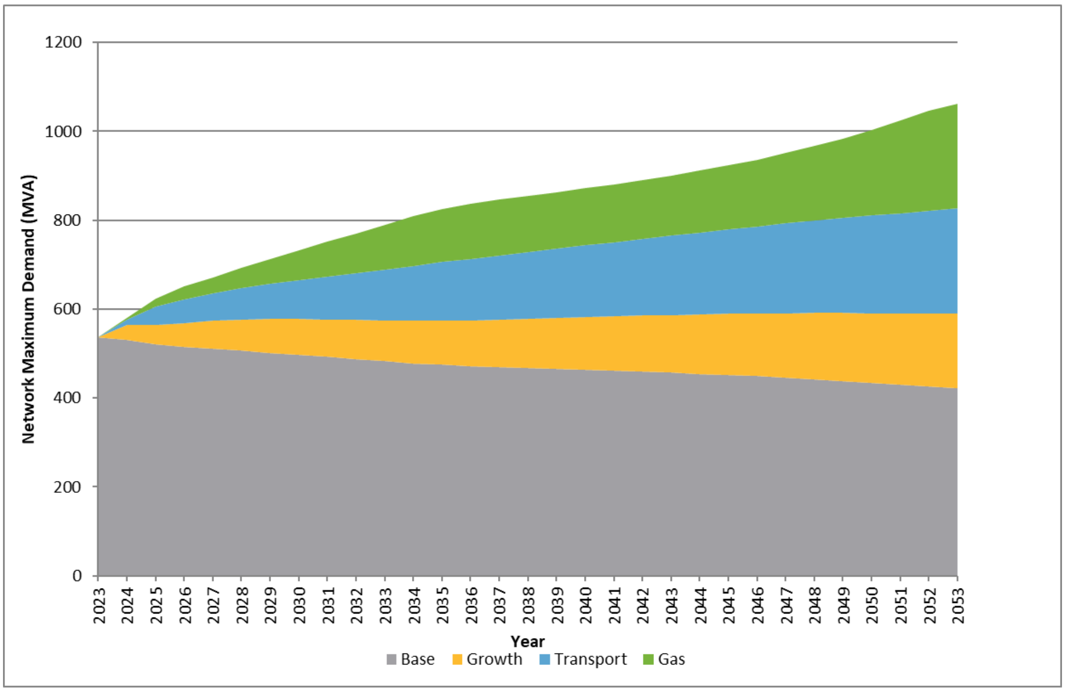

Figure 4-5 Forecast Demand on the Wellington Network 2023-2053

Figure 4-6 provides the year-on-year rate of change. Growth is high to begin with due to committed large electrification projects,[14] before settling back to long-term average growth of 2% per year.

[14] This includes the electrification of public transport and the conversion of coal boilers to electricity.

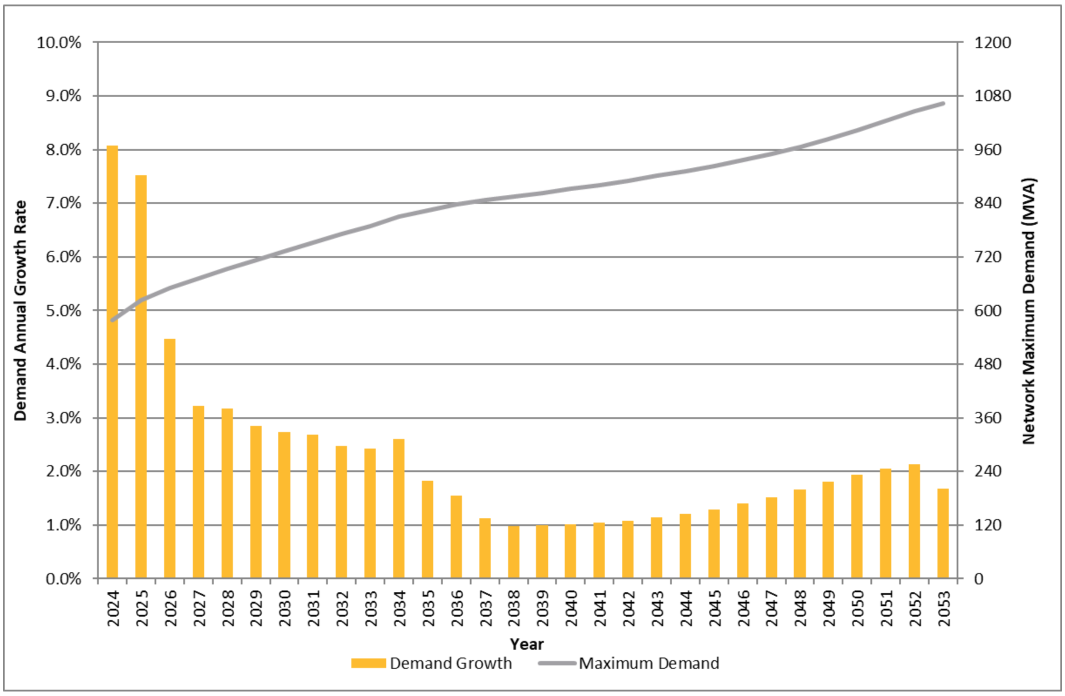

Figure 4-6 Demand Growth Rates on the Wellington Network 2024-2053

4.2.1.1 Demand Modelling Approach

WELL's 30-year peak demand growth forecast is a bottom-up aggregation of 18 different models. The demand models include:

- Known current projects, specifically public electrification projects;
- Population growth (residential, commercial and industrial), based on local council district plans;
- Electrification of private transport (residential and commercial);
- Electrification of public transport;
- Electrification of current gas use (main residential appliance types, main commercial processes);
- Impact of flexibility services, and
- Improving appliance efficiency.

Each model includes low, expected, and high-demand scenarios, forecasting the contribution to total peak demand in 2050. Energy conversion rates (e.g. gas to electricity), appliance consumption rates, and efficiency improvement rates are derived from expert external sources. A growth curve is then applied to each scenario, spreading the growth over the 30-year study period. The growth curves assume the following:

- Known public transport electrification (buses, interisland ferries, increased train service capacity) – Aligned with project delivery plans.
- Electrification of private transport – aligned with the ERP growth curve.
- Population growth – aligned with local council growth plans.

- Gas transition – growth delayed until 2025 (after the Gas Transition Plan is finalised) and then gradual growth until the late 2030s after which growth is forecast to accelerate to reach the 2050 end state of electricity replacing all gas use.

The delayed gas growth curve means that the uncertainty of the gas transition has a minimal impact on demand in the 10-year AMP window. The key factors driving demand growth over the next 10 years and the network reinforcement investment programme are known public transport electrification programmes, forecast electrification of transportation (both private and public), and population growth.

The primary use of the growth models is to inform the network capacity assessments and network growth programme provided in Section 9. Each subtransmission growth model is aligned to the 30-year growth profile to ensure the network capacity assessments include the ERP-related growth forecasts.

The 30-year growth models are also used for a number of secondary tasks such as informing the timing of investments in supporting processes like LV visibility, network management tools, and other capabilities needed to provide flexibility services.

4.2.1.2 Immediate Electrification Trends

The growth models include actual new electrification projects and trends we are seeing on the network. The uptake of EVs is increasing rapidly. While the growth rates are not exponential yet, the vehicle fleet has increased on average by ~60% for the last three years.

There are also several large public transport electrification programmes currently in progress. These programmes are driving the early spike in demand growth shown in Figure 4-6. Electric public transport is a large consumer of electricity and will represent a significant proportion of future network demand.

EV Growth

In late 2017 WELL conducted a trial to better understand the home charging behaviours of EV owners and how they could potentially affect electricity demand. The trial showed that an EV would add at least 30% additional household load. As Wellingtonians transition from fossil fuel-powered vehicles to electric, the impact on network demand will be significant, accounting for 40% of the total increase in future electricity use.

Wellington is already seeing a rapid uptake in electric vehicles. As of 31 December 2023, the WELL network area is home to approximately 266,000 light passenger vehicles, with 12,000 of these being electric or plug-in hybrids.[15] The growth of the electric light passenger vehicle fleet was relatively steady until the introduction of the Government's Clean Car Discount programme in 2021, which drove a significant increase in the rate of EV registrations. The trend in the number of EVs as a proportion of the total light passenger vehicle fleet in WELL's network area is shown in Figure 4-7.

[15] Waka Kotahi Open Data Portal

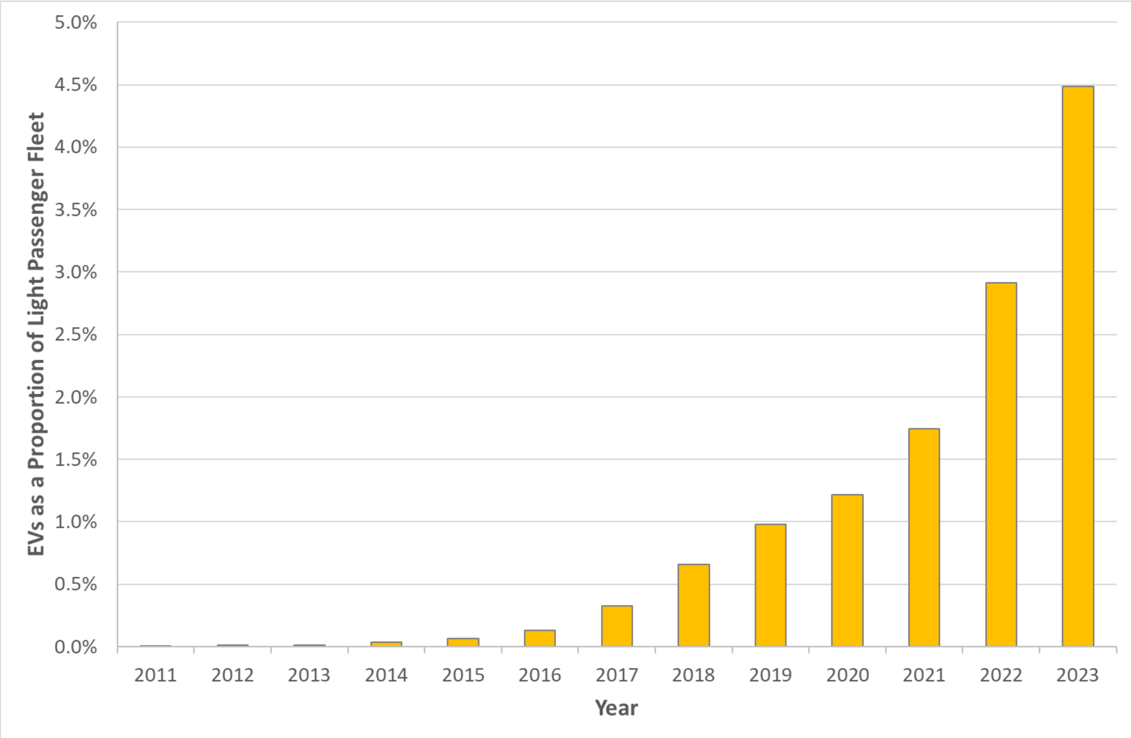

Figure 4-7 EVs as a Proportion of the Light Passenger Fleet in WELL Network Area

EDBs are currently unable to access information about EV charging locations. Networks need this information to manage the secure connection of EV chargers and to manage congestion on the LV network they are connecting to.

Electrified Public Transport

Figure 4-6 shows that the forecast peak demand growth in the next three years is greater than 4% per year, significantly higher than the long-term 2% per year average. This is because of public transport electrification projects that are already underway. The ongoing electrification of the bus fleet[16] and increasing the capacity of the electric rail services[17] will add 5% to the network's peak demand. WELL's long-term demand forecast also includes electrifying the remainder of the bus fleet and the electrification of air transport. Figure 4-8 provides a summary of WELL's forecast of new public transport connections.

[16] https://www.gw.govt.nz/your-region/news/regional-council-forges-path-for-transition-to-all-electric-bus-fleet/

[17] https://archive.gw.govt.nz/assets/2.Future-rail-fact-sheet-Wellington-Metro-Upgrade-v3090920.pdf

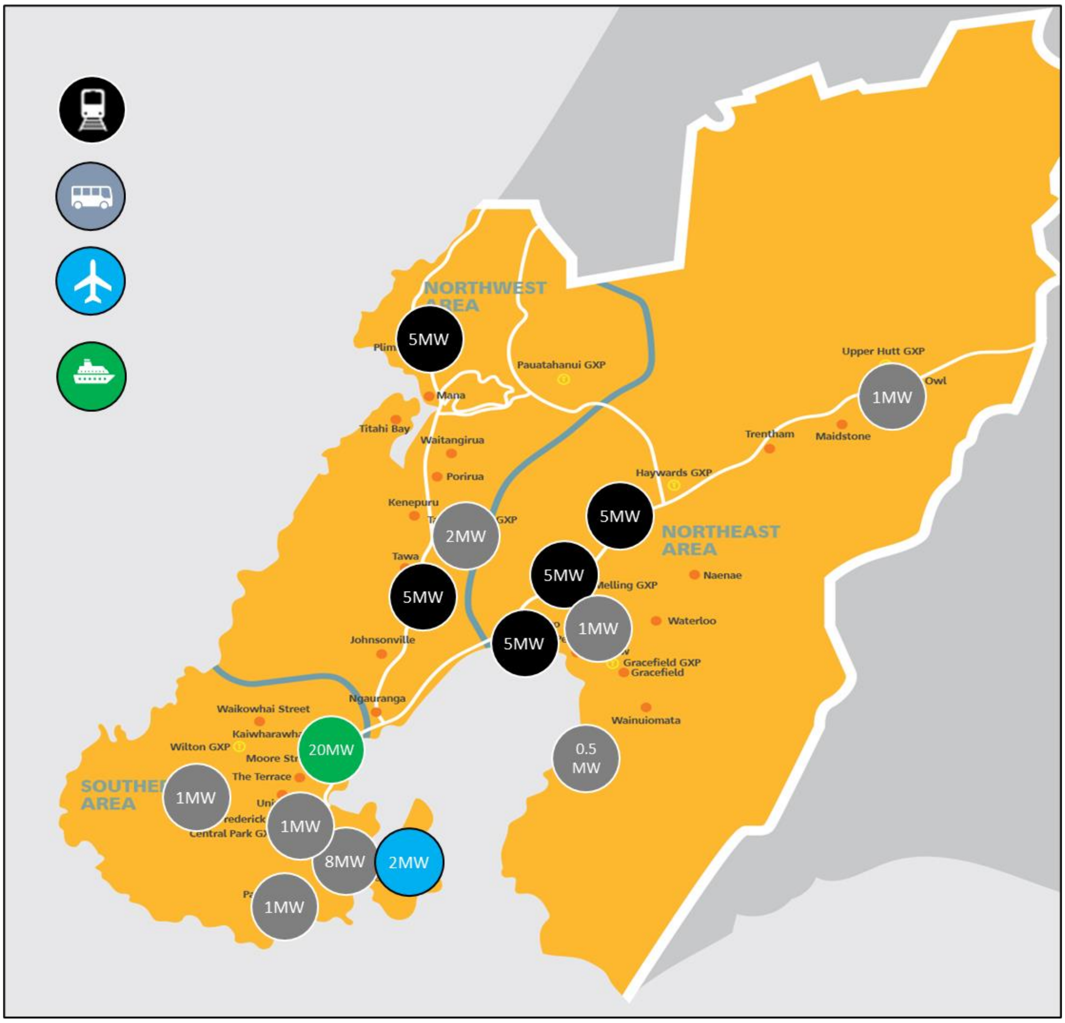

Figure 4-8 Major Public Transport Electrification Projects in the WELL Network Area

4.2.1.3 The Impact of Shifting Reticulated Gas Use to Electricity

Under the ERP the government will develop a transition plan for natural gas by the end of 2023. Until this plan is published, it is not known what impact it will have on the demand on WELL's network. Fossil gas use could transition to a biogas substitute, hydrogen, or to the electricity network.

The growth forecast assumes the transition will be from natural gas to electricity, as it is likely that some customers will choose to transition their own gas use to electricity regardless of government policy.

The potential transition to electricity would have a significant impact on the demand on WELL's network. Approximately 55,000 properties have a reticulated natural gas connection, typically used for water heating, space heating, and cooking, which represents one third of WELL's residential customers. WELL's network has been historically designed and operated in a manner that reflects this prevalence of gas as a residential fuel, due to gas-heated houses typically having a very low after diversity maximum demand (ADMD).

As an increase in electric heating will inevitably increase WELL's winter peak demand, WELL's future load growth, and hence any network constraints and reinforcement required, will remain highly uncertain until the national gas transition plan is finalised.

Case Study 2 – The Impact of EVs and the Gas Transition on the Low Voltage Network

The transition to electric vehicles and from gas use to electricity for residential space and water heating will have a large impact on the low voltage network, increasing the demand from existing connections. To better understand the impact on the LV network, WELL commissioned ANSA in 2023 to undertake an LV impact assessment on all its low voltage networks located in residential areas.

The desired outcome was to determine the proportion of assets that were likely to become constrained and require upgrade for each LV network, across a range of different future EV uptake and gas-to-electricity transition scenarios. In turn, given the upgrade costs of each asset type (distribution transformer, LV cable, and LV overhead line), this information has been used to calculate the capex requirement by regulatory period for a given constraint risk threshold and decarbonisation scenario. This capex forecast is shown in Figure 4-9. The figure compares the cumulative LV reinforcement capex (the capex to solve LV constraints) under the three growth scenarios that were modelled.

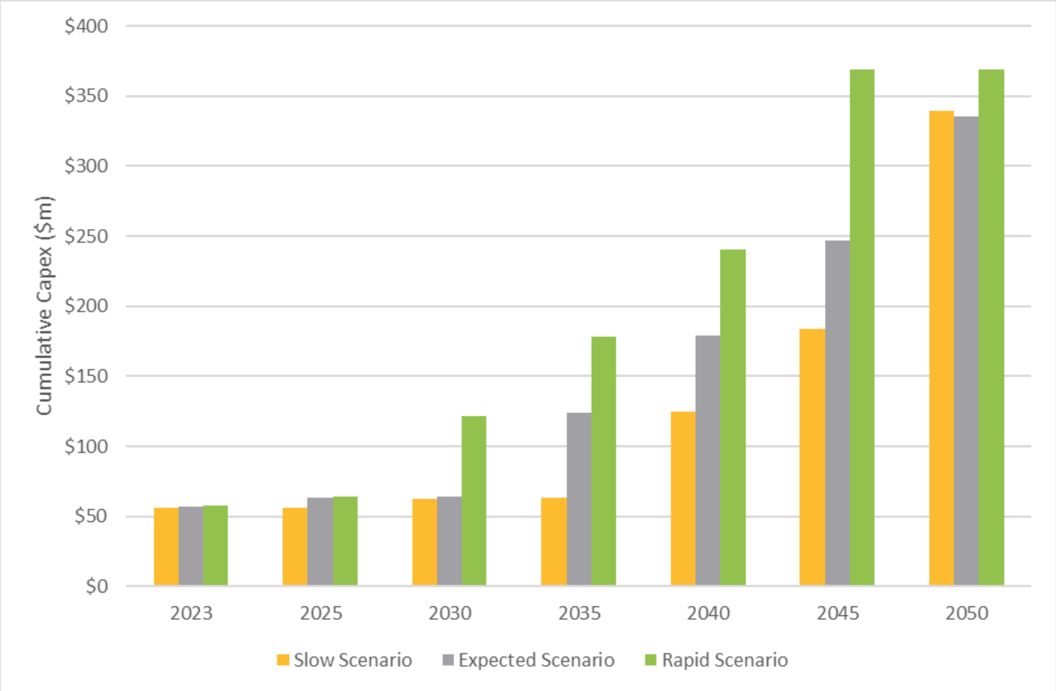

Figure 4-9 Cumulative LV Reinforcement CAPEX by Regulatory Period and Growth Scenario

The results provide important insights into the future capex required to mitigate network congestion, in addition to that required to manage asset age and condition. WELL has incorporated the resulting LV Network Growth capex forecast into this AMP.

The ANSA study is discussed in more detail in Section 9.7.

As well as a high prevalence of gas as a residential fuel, there are a number of large commercial and business users of gas on the Wellington network. DETA has surveyed large gas users in Wellington to assist in the planning of the transition to alternative energy sources like electricity. The responses to the survey suggest these businesses may have 90 MW of gas load that could transition to up to 40 MW of additional electricity use.

WELL supports the continued use of gas as a transition fuel. Continued use of the existing gas transmission and distribution networks maximises the value to the community of those existing assets while delaying some of the capital expenditure required to reinforce the electricity distribution network to support the electrification of heating for a significant proportion of WELL's customers.

4.2.2 DER and Flexibility Services

Much of the ERP-related demand growth will be related to DER: customer-owned devices that can be used to generate, store, or manage electricity. These devices are connected in homes and businesses and form part of the potential to support the local distribution network. An example of DER is smart, web-enabled EV batteries and chargers. The battery charging can be contracted to be remotely managed, delaying the charging until the electricity network is not congested or to charge during solar periods when electricity prices are lower. Flexibility services which are connected and managed could aggregate the management of consumer DER to help contribute to the balance of demand and supply in the electricity network and support its efficient use.

The Electricity Sector has identified the development of flexibility services as being a key to enabling the delivery of New Zealand's Emissions reduction targets. The Ministry for the Environment's '*Emission Reduction Plan',* the Authority's '*Updating the Regulatory Settings for Distribution Networks'* consultation, Transpower's '*Whakamana i Te Mauri Hiko',* and Boston Consulting Group's *'The Future is Electric'* all highlight the central roles flexibility services will have in spreading out the investment in new capacity, managing demand and supply uncertainty, and helping to manage the size of customer bill increases. While EDBs will also benefit from using flexibility services to avoid or delay investment in new capacity, they have a more direct need for these services: managing the connection of large new devices as customers shift from using fossil fuels to electricity.

Flexibility services for new smart connected managed DER are also in their infancy and still need to be developed into an industry-wide solution that will provide the scale needed to manage peak demand electricity use needed to release the full value stack of benefits. There is uncertainty about how effective these services will be as an alternative to building traditional capacity or whether they will be available every time a network will need them. While the industry recognises the potential value, the capability still needs development and it still needs to be confirmed whether the expected benefits will be realised.

The development of flexibility services to the scale needed will also take time and there are a number of early steps needed to ensure networks can accommodate these large DER devices before they are actively participating in a flexibility response, i.e. the steps needed to securely connect large DER within homes and businesses in the period before flexibility services are available. The aggregation of large smart DER provides a large load that can be used to shift and smooth the supply of electricity if it is coordinated, but if that same load is uncontrolled, it is large enough to impact the security of supply.

This section discusses the early steps needed to ensure these devices can be securely connected while flexibility services are being developed. The section then considers the steps needed to develop flexibility service, highlighting the 'least regret' actions discovered by WELL's EV Connect project.

4.2.2.1 Managing Peak Demand Before Flexibility Services Are Available

Before flexibility services have been developed as a meaningful demand management response, EDBs must develop processes and tools to accommodate large DER onto their networks. As part of WELL's response to the May 2022 ERP, it has started to model and test the impact of the large-scale connection of DER to its distribution network. WELL's studies have indicated that 50% penetration of EV chargers larger than 2.5 kW would exceed what the Wellington network has been designed to accommodate.

The simultaneous operation of large DER risks causing LV networks to exceed their safe operating limits. The operating limits include both thermal and voltage limits, with both needing to be managed to provide a secure supply. Currently, EDBs have no visibility of where many of these devices are connecting and have no way of ensuring that they will operate within the network's operating constraints.

EDBs will need an early form of a flexibility service to manage the rapid connection of large DER. Important early steps are needed so that networks can manage, aggregate and coordinate the connection of large DER so their combined operation remains within the network's operating limits. These are also early steps in the development of a full flexibility service – they provide a simplified flexibility service providing network security while the industry develops flexibility services that deliver the full value stack. The early steps, preceding the development of the full flexibility services are:

1. Customer education and strong peak period price signals to encourage customers to use electricity during off-peak periods, especially large new appliances like EV chargers.

2. An application process for the connection of large DER (over 2.5 kVA) to provide EDBs with visibility of where DER want to connect so that they can test whether the network has the capacity to securely connect that device. There is currently an application process for solar devices, but not for other DER like EV chargers. The process will need to be automated to streamline the connection process.

3. Strong incentives or standards to ensure DER devices are capable of being remotely managed and can participate in flexibility services.

4. All large DER are to be registered and participating in flexibility services so that their use can be managed away from peak demand periods on the network.

These four steps will help EDBs to accommodate DER, providing a stable platform to facilitate the development of more complex flexibility services and a market for trading flexibility. This approach has worked well for managing solar DER in South Australia. Solar devices that are registered to a central platform and are participating in flexibility services are not restricted in how much electricity they can export back onto the network. This provides the network operators with the ability to dial back export rates on the rare occasions when network security is at risk. Those not registered and participating in flexibility are heavily restricted in how much they can export. The restrictions reflect the impact that their unmanaged operation has on the network.

The implementation of these changes will either need very fast policy updates or it may be that networks will need to apply them through their own network connections standards. It could be that initial implementation is via network connection standards with the permanent solution reflected in a later Electricity Code change.

Case Study 3 – Coordination of Large DER

Figure 4-10 provides a simplified example to illustrate why the use of large DER needs to be coordinated. The example uses a sample LV network with a 300 kVA transformer and assumes 30% of households have an EV charger. If all large EV chargers connected to an LV network charge at the same time when the network is already busy, the network operating limits will be exceeded, potentially resulting in outages or unacceptably low voltage.

However, if large EV chargers are smart and are participating in a flexibility service, their combined use can be co-ordinated to remain within the network operating limits. Doing this ensures that EVs are charged and ready to be used when customers want, without their use impacting the supply of electricity to other users of the network.

Figure 4-10 Example Impact of Large EV Charger Management on LV Network Capacity Without Charger Coordination (Left) and With Charger Coordination (Right)

The development of flexibility services is complex and will need time and funding to develop. EDBs will not have the allowances to develop flexibility services or to purchase those services until the next regulatory period in 2025. Furthermore, EDBs will need to develop an Advanced Distribution Management System and Distribution System and Operator SO capabilities to incorporate flexibility services into their demand response. Experience from WELL's sister companies in Australia shows this to be a multiple-year process. An early form of a flexibility service and a change in customer behaviour is needed before then to manage the connection of large DER and to shift electricity use to off-peak periods.

Extending Hot Water Ripple Control

Wellington has 55,000 gas connections, providing hot water heating, space heating, and cooking for residential customers. The potential conversion to electricity reflects a significant increase in peak demand. EDBs will need to extend their existing hot water ripple control systems to capture the transition of gas to electricity in the period before flexibility services have been developed as a viable way of managing this new load. This will require:

- Funding to extend the capacity of EDBs' ripple plants, and
- Policy changes to support the transition of hot water heating onto ripple control.

Without extending this capability, networks will not be able to maintain a stable network until flexibility services have been developed to provide an alternative response, or networks have had time to build new traditional capacity.

4.2.2.2 More Efficient Network Services Using Flexibility Services

Assuming that networks can securely managed the rapid connection of large DER while flexibility services are being developed, flexibility services could provide an opportunity for EDBs to deliver more electricity through the better utilisation of the existing network. The better utilisation of the existing network will mean that EDBs can delay or avoid the reinforcement of their networks with larger equipment of greater capacity. Figure 4-11 illustrates how if the new demand is not well managed, then higher levels of investment will be required to increase the capacity of the network. Conversely, if the new demand can be managed to utilise existing capacity headroom during the less congested off-peak periods, then further network investment could be deferred, helping to keep long-term prices low for customers.

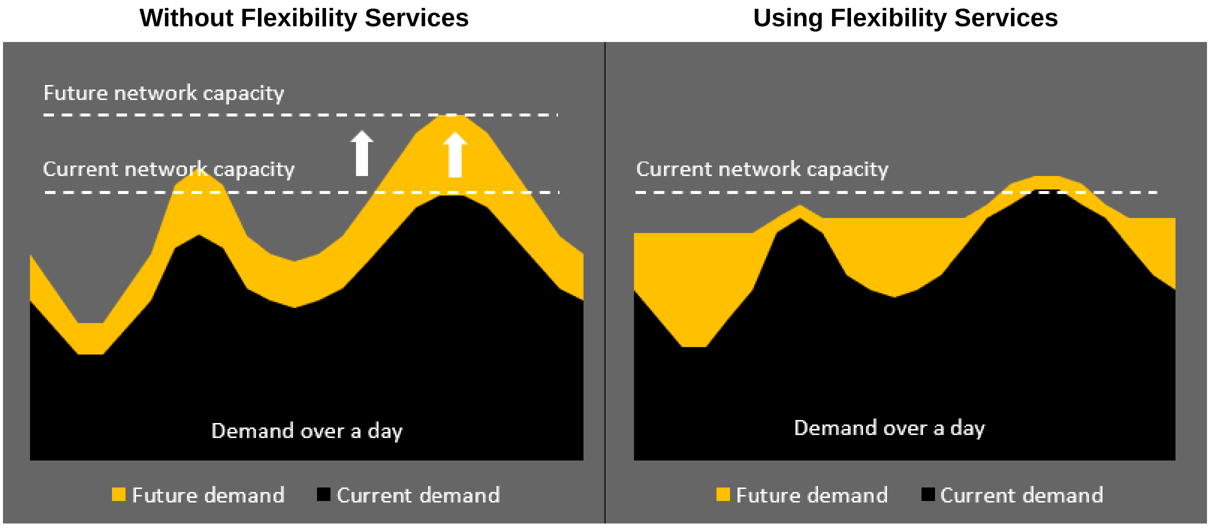

Figure 4-11 Impact of Demand Control on Network Capacity Requirements

Communicating smart EV chargers provide the greatest opportunity for shifting demand using flexibility services on the Wellington network, as the chargers could be actively managed so that vehicles are only charged during off-peak periods. Further benefits could be realised by using the EV battery to supply the household during peak demand periods, reducing network congestion even further. Case Study 4 considers the opportunities for using customer appliances to shift demand away from congested periods on the network, confirming that EV charging and hot water appliances offer the best devices to use for flexibility services.

Case Study 4 – Finding the Best Way to Shift Demand

WELL has been part of Concept Consulting's EV study work programme. A key deliverable of the programme was to establish what load can be shifted to a less congested period. This would allow EDBs to focus on the development of flexibility services for customer DER that can be practically moved.

The Concept Consulting EV study analysed two points in time:

1. 'Today', being a breakdown of electricity consumption between end-uses as per EECA's Energy End-Use Database, and
2. 'Electric 2050', being the increase in average per household electricity consumption by 2050 assuming the degree of electrification proposed by the Climate Change Commission.

The study found that prior to any demand management, the biggest driver of today's average uncontrolled household contribution to the system peak is space heating, followed by water heating, then cooking, with other appliances driving the remaining 30% of peak demand.

By 2050, if households have no incentives to manage when they charge their EVs, unmanaged peak per household demand will increase by 45%. This increase is largely from EVs, with some increased contribution from water heating (due to gas being removed), and small offsets from other uses. In total, EVs would represent 30% of unmanaged peak demand per household, as shown in Figure 4-12.

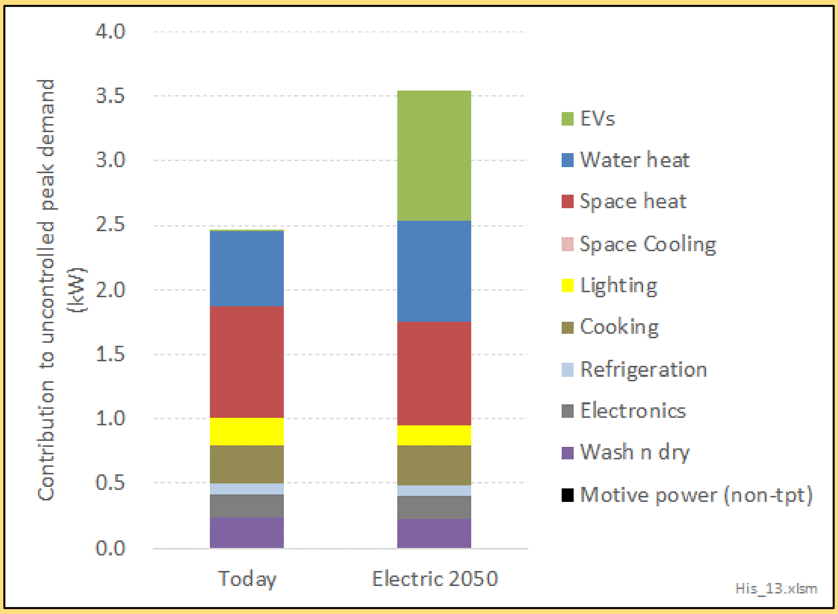

Figure 4-12 Average Contribution to Peak Demand Prior to Demand Management

The study looked at what appliances have the most potential for demand management. Figure 4-13 shows an estimated breakdown of the potential for appliance demand management. The key takeaway is that EV charging and water heating have the most potential for load management.

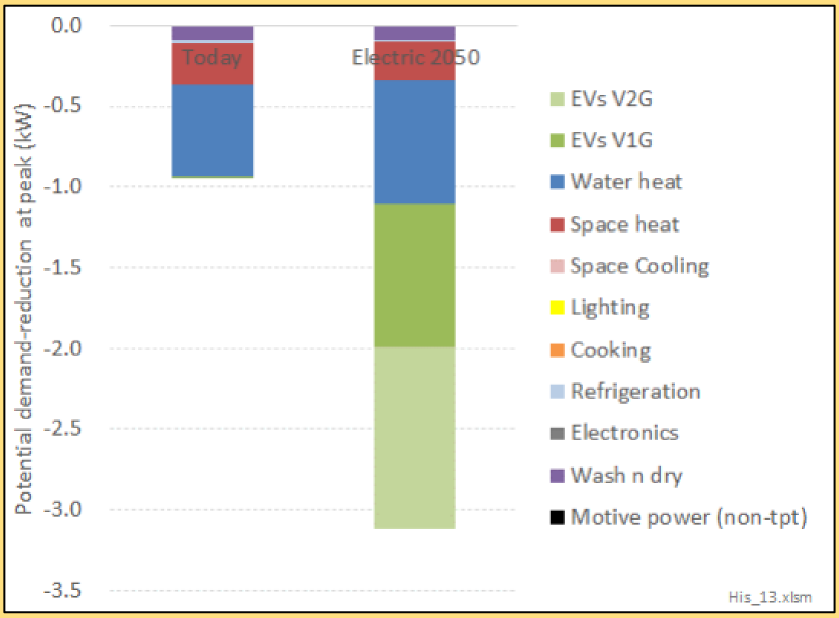

Figure 4-13 Household Potential for Appliance Demand Management During Peak Demand

While the study is based on national data, WELL's network has the highest proportion of residential gas heating in New Zealand, and its urban environment is better suited to EVs than other network areas. Therefore, the potential for controlling peak demand through the use of flexibility services is even higher in Wellington.

4.2.2.3 Development of Flexibility Services and a Flexibility Services Framework

Flexibility services are forecast to be valuable across the electricity supply chain. Sapere has estimated the value of flexibility services to be $6.9b from a range of different uses, from deferring distribution and transmission network reinforcement to retailers arbitraging the spot market for purchasing electricity.[18] However, these are only forecasts and have yet to be released. The industry is in the early stages of its development and the implementation is complex and requires the coordinated development of new capabilities across the supply chain.

WELL's EV Connect Roadmap[19] and the FlexForum's Flexibility Plan 1.0[20] provide the key actions and steps needed to develop flexibility services in the form needed to manage the secure connection of DER and to support the ERP. The actions also include the steps needed to provide flexibility at the scale needed to provide an alternative to building traditional approach to congestion of building more capacity. Of those actions, there are eight critical steps:

[18] D. Reeve, T. Stevenson & C. Comendant (2021) Cost-benefit analysis of distributed energy resources in New Zealand: A report for the Electricity Authority, Wellington, New Zealand

[19] https://www.welectricity.co.nz/about-us/major-projects/ev-connect/

[20] https://flexforum.nz/flexibility-plan/

1. **Coordinated implementation**: WELL's EV Connect programme identified industry leadership as a key driver for the development of flexibility services. The actions needed span the flexibility supply chain and require a coordinated approach.

2. **Understand consumer preferences for flexibility services:** For flexibility services to be developed to the scale needed to provide a viable wire alternative, customers must have a smart device that can be remotely managed and be willing to participate in flexibility services. The industry must develop services that customers are comfortable participating in.

3. **Implement an industry-wide hierarchy of needs**: Develop a hierarchy of needs framework in the Electricity Code to ensure network operators (EDBs and Transpower) have access to flexibility services in emergency situations when direct intervention is needed to 'keep the lights on'. These are rare events that would have a limited impact on competing flexibility services.

4. **Ensuring DER are smart and are participating in flexibility services:** This includes ensuring all large DER are visible and registered with a flexibility provider – so that EDBs can ensure they are connected securely, and their continued operation remains within the network security limits.

5. **EDBs to develop an LV management capability**: Forecasting where flexibility will be needed and incorporating flexibility services into their asset demand response. This will allow EDBs to identify network constraints and where flexibility services could be a viable wire alternative. LV Management systems combine spatial GIS data with ICP level consumption and power quality data to forecast demand and network capacity constraints. These systems are complex and will take time to develop. LV management is a precursor to Distribution System Operator capability.

6. **Streamline access to ICP level data**: EDB LV management systems require ICP data – without the data EDBs have no visibility of LV constraints or where they could use flexibility services. The provision of ICP data includes ensuring all privacy responsibilities are met.

7. **Flexibility provider tools that coordinate DER and aggregate a demand response**: Flexibility providers need to develop the capability to aggregate and coordinate the management of multiple DER. The tools must have common communication protocols that allow services to be coordinated with buyers.

8. **EDBs are funded to develop and purchase flexibility services**: EDBs are not funded to purchase flexibility services. They do not have OPEX allowances to purchase services and the IRIS mechanism does not allow OPEX/CAPEX substitution if the deferred CAPEX benefits span multiple regulatory periods. Until EDBs have regulatory allowances to purchase services, their use of flexibility services will be limited to small-scale trials and tariff services. This is being discussed as part of the IM review.

Significant Development in EDB Capability

The 'least regrets' actions provided above are the key capabilities that the industry needs to develop to enable flexibility services. The EDBs' actions represent a significant investment in new capability that will take time and additional allowances. Purchasing a full data set needed to support the development of LV visibility is likely to cost over $0.5m per year, and the ongoing software costs to collect, store, and analyse the data could double this. Forecasting network constraints and managing the application of flexibility services requires the development of an LV Advanced Distribution Management System (ADMS) which combines GIS spatial data with ICP level consumption and voltage data. In South Australia this capability cost approximately $37m (including $4m per year in operating costs) and took five years to implement for the

900,000 connections they service. While the deployment of similar technology in Wellington will cost less, the investment is still significant. It is also important to note that the funding for these new investments will not be available until the next price path reset in 2025.

The investment in the current hot water ripple control systems provides a useful comparison. This capability has required EDBs to invest millions in the ripple control system, relays, and communication network. Retailers and meter providers have also had to install ripple meters and their own communications. WELL agrees with the industry that flexibility services will be valuable, but it is necessary to highlight that the development of this capability will take time and investment to develop.

4.2.2.4 Supporting Regulatory Framework and Hierarchy of Needs

Careful planning is needed to design a regulatory framework to ensure flexibility services are available whenever they are needed by networks (both EDBs and the System Operator) to maintain network security. Flexibility services first need to be available in emergency situations – when direct intervention is needed to ‘keep the lights on’ – and then once the distribution network and grid is operating stably, to be available wherever they provide the most value to customers.

Practically this will mean the development of a flexibility market which assigns flexibility services to where they provide the most value (i.e. who will pay the most to buy the services) and will have a set of prioritising rules that provides emergency access to all services. The regulatory framework setting the terms and conditions for services between EDBs and retailers provides an example of how this could work in practice. The Default Distribution Agreement (DDA) outlines that parties other than EDBs can provide load control services on the distribution network but must provide EDBs and the System Operator access to those services in emergency situations. Similar rules could be expanded to include flexibility service providers.

Flexibility services using customer devices connected to distribution networks could also be directly managed by parties outside of the distribution network i.e. the system operator directly controlling devices to manage grid-level security. EDB will also need the ability to ensure that the operation of these devices remains within the network's operating limits. EDBs are responsible for distribution network quality and face fines of up to $5m per quality breach for non-performance. Therefore, an EDB must have direct oversight of how these devices are being used so that they can meet their regulatory obligations.

4.2.3 Changing Customer Expectations

New technologies are offering customers new benefits and opportunities and are changing how they use electricity. Table 4-3 summarises the changing customer requirements and the resulting impact on the distribution network.

New Customer Requirement	Impact on Network	Potential Network Investment
New large appliances like EV chargers.	Residential ADMD increasing beyond what the low voltage network was designed for.	Reinforcement of the LV network. Increasing distribution transformer sizes. The need for flexibility services to manage the uptake of large DER
Increased reliance on electricity as the sole household energy source.	Expectation of higher service quality and fewer outages.	Increasing network resilience.
Increasing use of flexible working arrangements, such as working from home.	Less tolerance for planned outages for maintenance in residential areas.	Deployment of mobile batteries (in place of diesel generators) to maintain supply to customers during maintenance activities.
Customers wanting to share spare electricity they have stored or generated.	Two-way power flows on the LV network. Voltage profiles becoming less predictable.	Increased visibility and control of the LV network.

Table 4-2 Summary of Changing Customer Requirements and Network Impacts

4.2.4 Changing How EDBs Communicate With Customers

EDBs have traditionally provided distribution services in the background of people's lives, with customers only becoming aware of the service when the electricity supply is unavailable. Retailers have been responsible for communicating with customers, and EDBs have had little direct customer contact. This has worked well in the past under the 'business as usual' operations in which distribution services have changed very little in terms of service provision and quality.

With the changes in electricity distribution services driven by the new customer requirements outlined in Section 4.2.3, EDBs will need to develop a different relationship with their customers. EDBs need to understand the changing cost-quality trade-offs that their customers are prepared to make and promote customer participation in the flexibility services that will be critical for managing the changing demand, discussed in Section 4.2.5. An indirect relationship through the Retailers will make this communication slow and difficult, and EDBs will instead need to develop new direct customer engagement practices.

4.2.5 Limited Spare Capacity

The past business and regulatory focus of closely matching demand and capacity and keeping prices low by not building new capacity before it is needed, discussed in detail at the start of Section 4.2, has worked well in the past environment of low, stable growth. However, it now means that the Wellington network does not have the capacity available to meet the ERP-related demand increases. The capacity that is available through load management and the limited network headroom, is quickly being used up by the rapid uptake of EVs and the electrification of public transport.

Figure 4-14 shows the forecast increase in maximum demand at WELL's zone substations relative to their rated capacity from 2023 to 2033. Loading beyond these capacity limits can either be managed using existing tools (for example temporary load transfers or flexibility services) or require an asset upgrade where these tools are insufficient. This illustrates the extent to which decarbonisation will drive the need for WELL to reinforce its network.

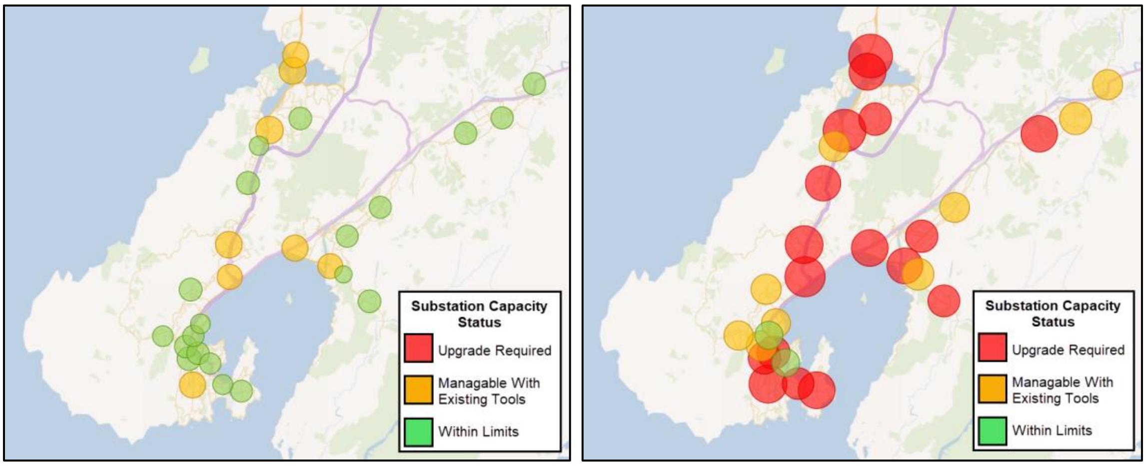

Figure 4-14 Change in Zone Substation Demand vs Capacity from 2023 (Left) to 2033 (Right)

4.2.6 Asset Replacement Programme

Several of WELL's largest asset fleets are coming to the end of their useful lives. Specifically, the replacement of underground cables and power transformers has started and will continue over the next 25 years. The replacement of these two asset fleets is a step change in the replacement programme.

Figure 4-15 provides WELL's forecast asset replacement investment profile for the next 30 years. This expenditure profile excludes the impact of network reinforcement programmes, which in reality will bring forward the replacement of many of these assets as the need for more capacity triggers their early replacement. The impact of network reinforcement has been excluded to demonstrate that even without the ERP, the Wellington network requires a step change in investment.

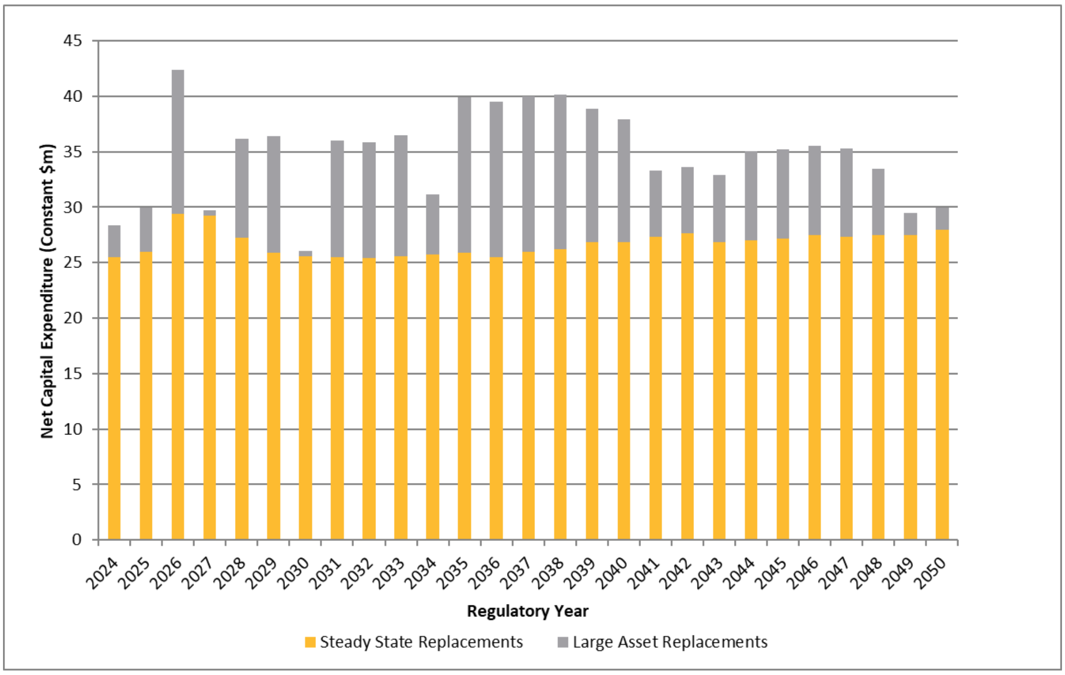

Figure 4-15 WELL's Asset Renewal Expenditure Forecast to 2050

The yellow-shaded asset classes reflect WELL's 'business as usual' ongoing asset replacement programme – the continuous and steady replacement of many low-value assets such as distribution substations, poles, and overhead conductors.

The grey-shaded asset classes reflect larger, low-volume high-value asset fleets that are replaced less frequently. The subtransmission cable and power transformer fleets reaching end of life represent a step change in investment requirements.

The alignment of this upcoming renewal expenditure with the network reinforcement programme means that assets being replaced due to health can be sized so that they will also have the capacity to meet ERP-related demand increases. As a result, WELL will be able to optimise the efficiency of its total investment programme, minimising the overall cost to customers.

4.3 WELL's Long-Term Investment Programme

Section 4.2 provided an overview of what's changing how we provide distribution service and what is driving a step change in network electricity demand and investment requirements. WELL's 30-year planning model provides future network investment requirements, and has highlighted two related step changes in investment:

- **Investment to provide new capacity**: The forecast 98% increase in peak demand requires WELL to invest in new capacity. This will require an investment in both traditional new capacity – larger equipment – and new demand management capability (flexibility services) that allows more electricity to be delivered using the existing network.

- **Replacement of WELL's two largest asset fleets**: The zone substation power transformer fleet and the underground cable fleets are coming to the end of their technical lives. In the previous 'business as usual' operating environment, the replacement of these assets started to enter the 10-year AMP planning window for the first time in the 2021 AMP.

Some of the assets due to be replaced are the same assets that require capacity upgrades. The 30-year combined capital expenditure programme rationalises the investment programme so that new assets have both the capacity needed to meet future growth expectations and are replaced before they adversely impact quality. The rationalised capital expenditure programme is smaller than the sum of the two individual programmes. The principles used to integrate the work programmes are:

- The capacity of the assets being replaced or upgraded will be based on the lowest long-term cost. In most cases this will mean replacing ageing assets with sufficient capacity to meet the expected increase in peak demand over its whole life. High installation costs and the relatively low incremental cost of installing larger assets with more capital usually means its less expensive in the long term to ensure an asset doesn't need to be upgraded mid-life with additional capacity.

- Where an asset is included on both the replacement and network growth programmes, an asset will be included only once and scheduled to meet the earliest of the asset replacement date or when new capacity is required.

4.3.1 30-Year Work Programme

WELL's forecast capital investment profile totals $2.2 billion over the next 30 years. Under the past business-as-usual operating environment, which has been focused on providing a steady and reliable supply of electricity, WELL's capital expenditure has averaged $42m per year for the last ten years. This is expected to increase to an average of $90m per year for the next 30 years.

The capital expenditure forecast for 30 years is shown in Figure 4-16. This has been smoothed in consideration of resourcing and other delivery constraints. Further programme smoothing will be needed as the work requirements and delivery constraints are defined.

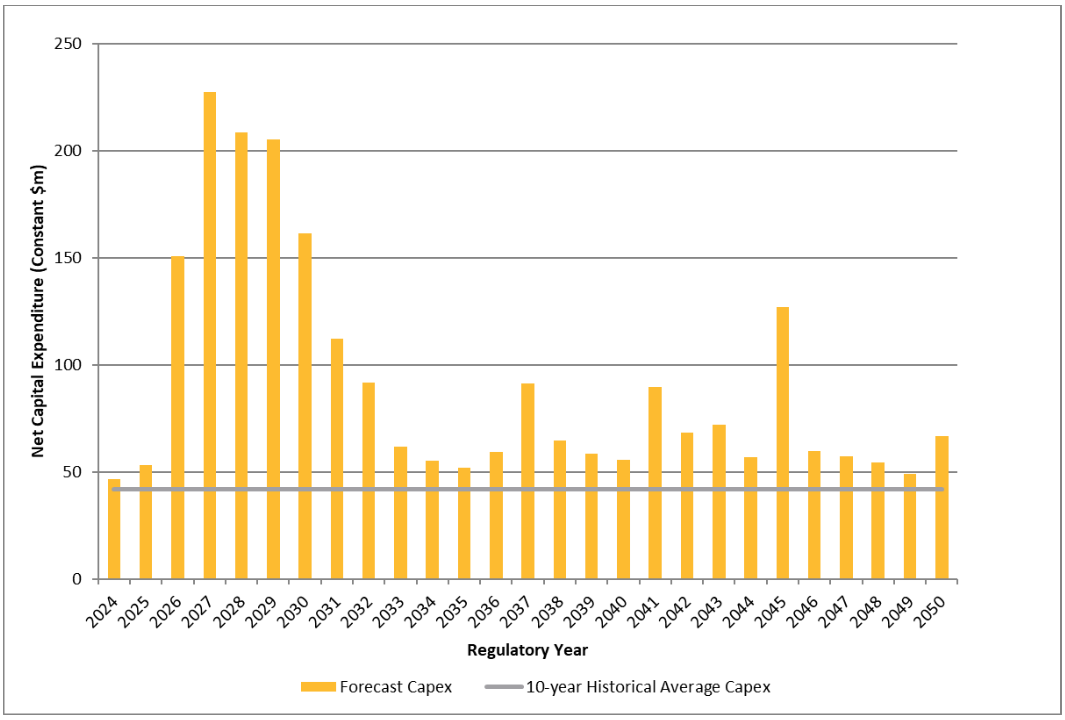

Figure 4-16 WELL's 30-year Capital Expenditure Forecast

Figure 4-17 provides a breakdown of when each different network needs reinforcing with new capacity. The 33kV subtransmission network will run out of capacity early and will be the initial focus of the investment programme. The 11kV and LV networks will be upgraded with additional capacity over the 30-year investment time frame. WELL has been working with ANSA to develop a 30-year network reinforcement model for the low voltage network.

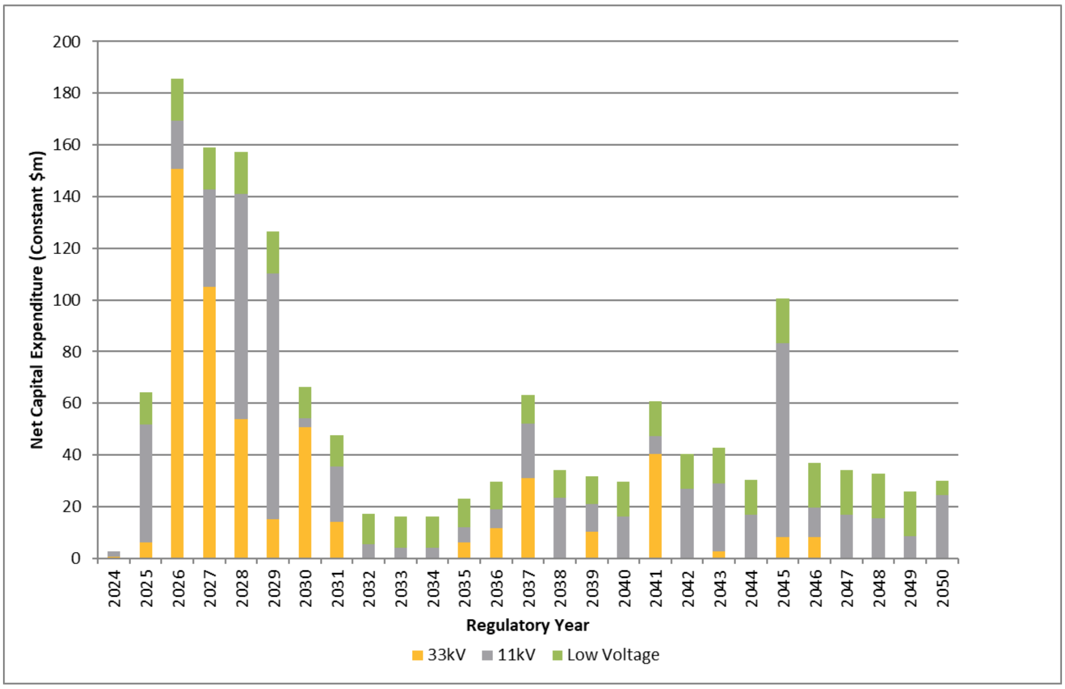

Figure 4-17 WELL's 30-year Network Reinforcement Forecast by Voltage

4.3.2 Comparing WELL's Capex Forecast to BCG's *'The Future is Electric'*

Boston Consulting Group's *'The Future is Electric'* report considered the investment that each participant in the electricity sector in New Zealand would need to make for the industry to support the ERP carbon reduction targets. The report calculated that EDBs need to make significant investments in new capacity and capability, totalling $22b over the next 10 years, rising to $71b over the next 30 years.

Scaling the distribution network investment forecast presented in *'The Future is Electric'* by WELL's ICPs, the volume of electricity delivered, and regulatory asset base (RAB) indicates that WELL's CAPEX forecast is lower than the BCG forecast, with the differences due to the economies of scale inherent in WELL's dense urban network. The comparison using the size of the RAB to scale the BCG forecasts provides a closer comparison as the RAB captures the higher economies of scale of the Wellington network. While the 10-year forecast is very close, there is still a long-term difference which reflects the uncertainty of forecasting more than 10 years out. This is shown in Table 4-3.

Forecast Horizon	BCG Forecast Scaled by ICPs	BCG Forecast Scaled by energy delivered	BCG Forecast Scaled by RAB	WELL Capex Forecast
10 years	$1.7 billion	$1.5 billion	$1.1 billion	$1.5 billion
30 years	$5.5 billion	$4.9 billion	$3.6 billion	$2.2 billion

Table 4-3 Comparing WELL's Capex Forecast to BCG's *'The Future is Electric'*

4.3.3 Increasing Costs

WELL has experienced higher cost inflation than the general national inflation and expects the electricity industry will continue to see higher cost inflation as work programmes increase and equipment and labour becomes even more scarce and constrained. *"The Future is Electric"* forecasts EDBs' capital programmes to be worth double the value of the total existing network (see Section 4.3.2). This will be at the same time as water networks are expected to start replacing New Zealand's ageing water infrastructure, placing further pressure on the availability of civil contractors. Figure 4-18 provides examples of changes in electricity industry costs since 2013 relative to CPI. Consideration will need to be given to how this industry-specific inflation is captured in the regulatory allowances.

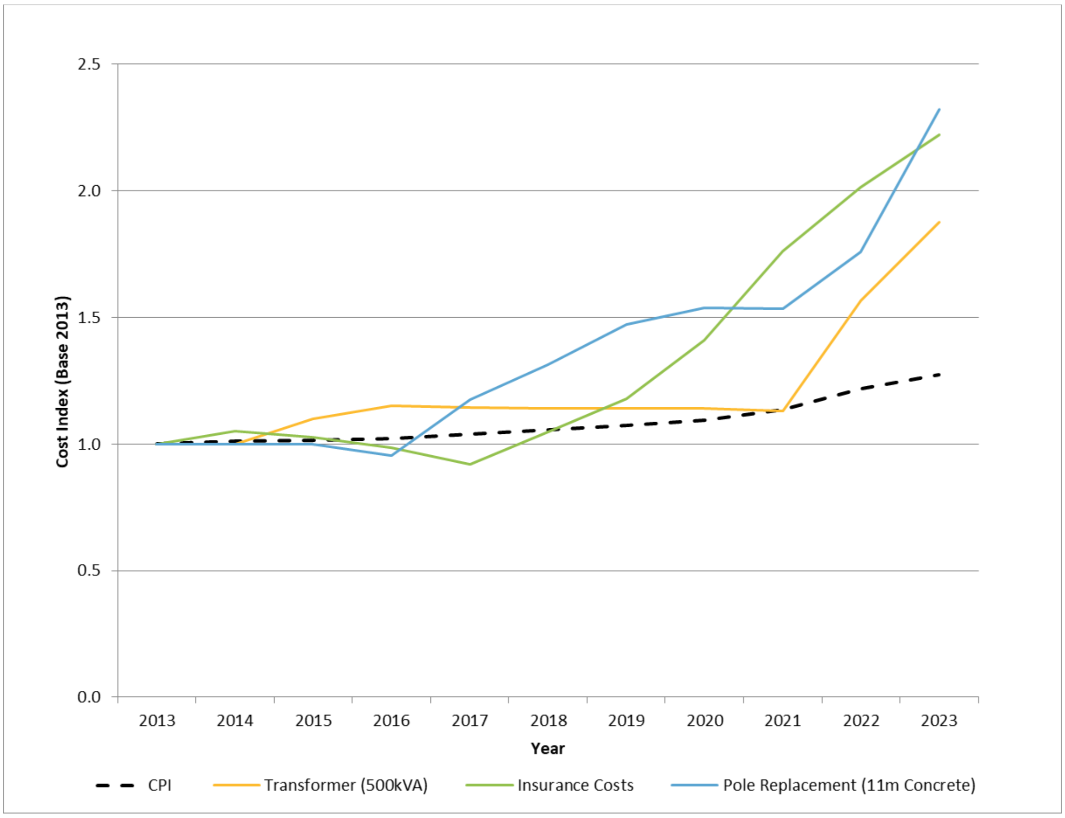

Figure 4-18 Examples of Cost Escalations Relative to CPI

The inflationary forecast used in this AMP is based on the Reserve Bank February 2024 monetary policy inflation forecast. While the next year's inflation is forecast to be high (the 2024 forecast is 3.8%), inflation is forecast to return to the long-term monetary policy target of 2%, WELL expects that industry inflation will continue to be higher than the national CPI inflation forecast due to continuing resource and materials scarcity.

WELL has submitted that the Commission consider an industry inflation forecast as part of the DPP4 price reset process.

4.3.4 Demand Uncertainty

EDBs will have to build new capacity to meet the 2050 emissions reduction targets. However, there is uncertainty around the rate of the demand increase and in what sequence that new capacity will be needed. Demand is the primary driver of the timing of network reinforcement investment programmes, and uncertain demand will result in networks having to adjust the order of the work programmes.

Specific drivers of demand uncertainty and work programme resequencing are:

- What will the substitute be for fossil gas? The electricity system will provide some or all of the energy use currently provided by natural gas. However, until the Gas Transition Plan is finalised, the exact proportion will not be known. Approximately half of WELL's forecast demand increase highlighted in Section 4.2.1, relates to the transition of gas energy use to the electricity system.

- WELL's demand forecast assumes that flexibility services will be developed to the scale needed to better utilise the existing distribution network. If these services are not successfully developed, networks will have to build more capacity.
- What will the speed of EV uptake be? EV uptake rates have exceeded that provided in the 2022 ERP, however demand has cooled significantly following recent government policy changes. Case Study 5 looks at the drivers behind EV update rates.
- Where will the growth be? Many EDBs have no visibility of demand on their LV networks and where customers are adding DER such as EVs. While distribution connection standards say that customers must apply to an EDB before connecting DG, there is no requirement for a customer to tell a network they are connecting large EV chargers or household batteries.

Figure 4-19 shows the levels of demand uncertainty in the peak demand modelling undertaken by WELL, providing an overview of the low, expected, and high 30-year demand growth scenarios. While the low and high ranges are extremes, this illustrates the potential variability in growth.

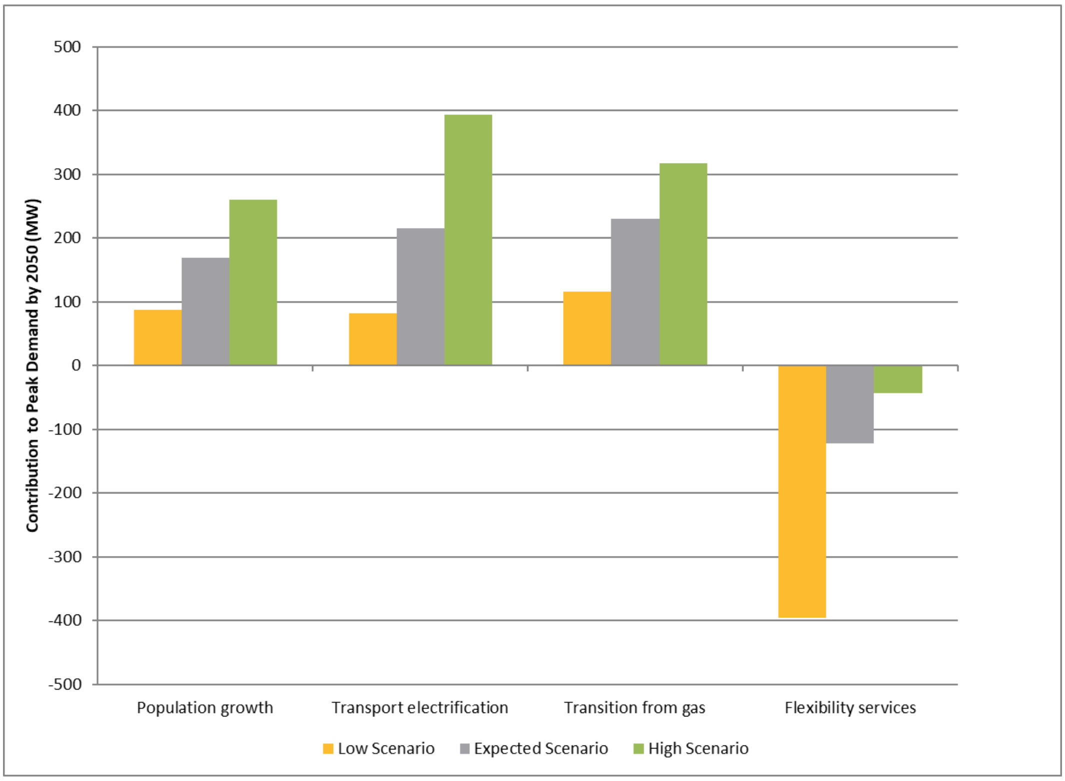

Figure 4-19 Ranges of Demand Uncertainty

The high growth rate scenario is not unrealistic: it assumes that the Government's Gas Transition Plan sets a fast exit starting in the next few years and that electricity becomes the primary alternative. The base growth scenario assumes the transition from gas to electricity starts in the next decade. The high growth scenario assumes that flexibility services are not as effective at shifting peak demand as expected. Again, given that flexibility services are not yet proven, this is not an unrealistic scenario. The high growth scenario also assumes EVs quickly gain price parity to fossil fuel-powered vehicles, accelerating their uptake.

Case Study 5 – The Uncertainty in EV Uptake Forecasts

EV uptake rates have been shown to be dependent on a range of drivers like the level of government subsidies, the resulting affordability of those vehicles, and suppliers' ability to keep up with the resulting demand.

EECA's 2019 electric vehicle growth scenarios[21] varied based on how fast the price of EVs reach price parity with internal combustion engine vehicles. The speed at which this occurs will be influenced by factors like production/technology costs, government subsidies, and other incentives. The EECA scenarios are shown in Figure 4-20, overlaid with the actual fleet size for 2021 to 2023 to illustrate the current situation.

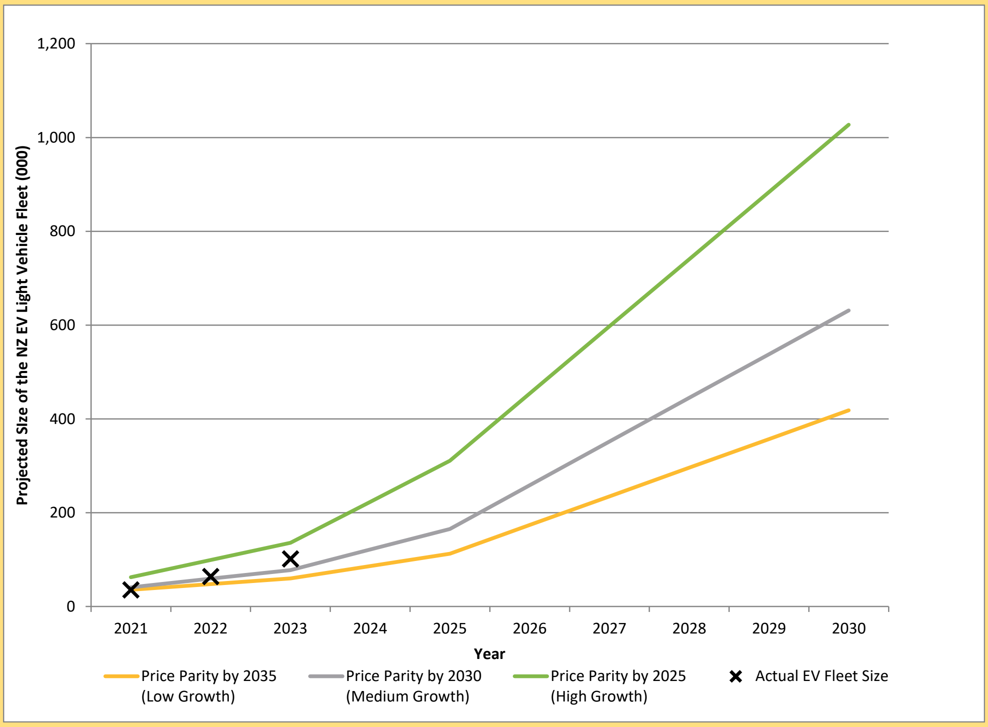

Figure 4-20 EECA's New Zealand EV Uptake Scenarios (2019) [21]

The Government's Clean Car Subsidy helped close the price gap between fossil fuel and EVs, leading to a surge in EV registrations from July 2021, followed by a large drop when the incentive was removed at the end of 2023, shown in Figure 4-21.

[21] https://www.eeca.govt.nz/assets/EECA-Resources/Research-papers-guides/EV-Charging-NZ.pdf

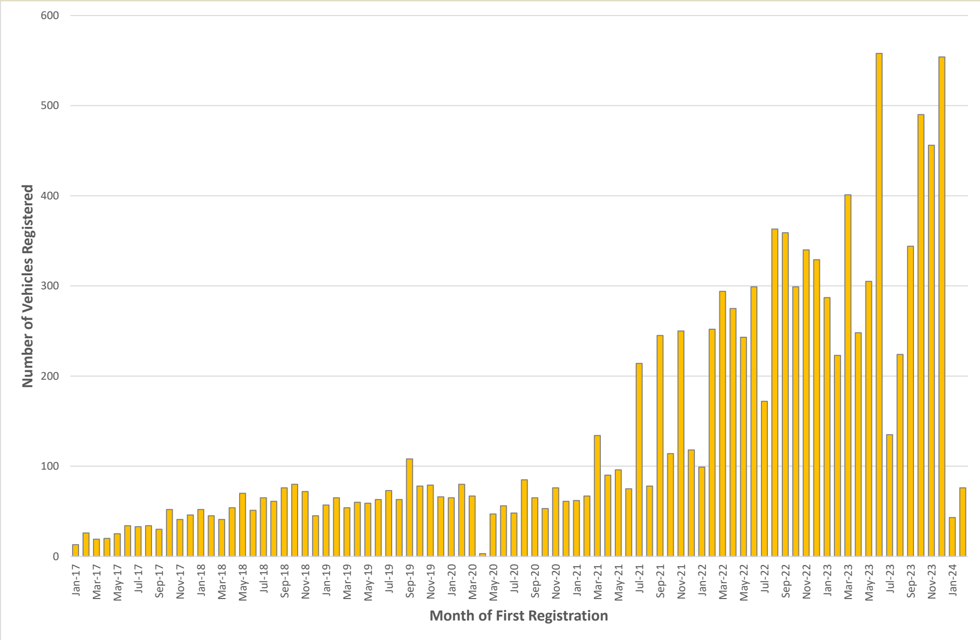

Figure 4-21 Monthly Registrations of EVs and PHEVs in the WELL Network Area

The influences of government subsidies, supply restrictions, the speed of technology improvements, customer choice, and customer charging habits, all make it difficult to forecast EV uptake and the associated impact on electricity demand.

4.3.4.1 The Impact of Demand Uncertainty

Networks know how much new capacity they will need to build to deliver their part in New Zealand's emissions reduction plan. On the Wellington network, WELL needs to deliver a 98% increase in capacity to allow Wellingtonians to shift from using fossil fuels to power their transport, homes, and businesses, to using renewable electricity. What is less certain is the sequence of the work programmes.

Forecast demand drives when new network capacity is needed. Fast demand growth means that EDBs will need to bring forward a work programme. Lower demand means networks can push back when they need to build new capacity. The judgement of when and what new capacity is needed will become more difficult. EDBs will not be able to precisely match demand and capacity as they have in the past. Some of the drivers of demand growth could result in rapid changes that may require networks to quickly change their investment forecasts. For example, exponential EV growth could quickly add unexpected new load within a regulatory period. Other changes, like confirmation of whether a renewable gas alternative to fossil gas will be viable, will be slower and the ability to change investment profiles within a regulatory period may not be as important.

EDBs will also need to judge what capacity the new investment will need. Network reinforcement investments will need to be able to deliver the demand growth over the life of the asset. If the EDB under forecasts the required size of the new asset, this could create a stranded asset if demand exceeds its capacity early in its life. The existing regulatory framework would mean that the customers will continue to fund the original undersized asset as well as paying for the new larger asset. Alternatively, if more capacity is built than is ultimately needed, customers will overpay for the service they require.

EDBs will need the ability to adjust the sequence of their work programmes in response to changes in demand growth rates. Networks will need to continue to refine their demand growth models and develop flexible planning processes that will ensure that new capacity is built before demand exceeds capacity and a secure electricity supply continues to be provided. EDB work programme sequencing, in response to rapid and volatile demand growth, will need to consider:

- Large subtransmission projects have long (up to three years) lead times. The work programme must consider faster-than-expected growth rates within the build window. Practically this means including a buffer that will ensure capacity is available before the fastest growth scenario within the build window.

- An EDB may have to adjust when it builds capacity to match the availability of resources. If other EDBs and infrastructure providers, both locally and internationally, are also investing in their networks, there is likely to be a worsening resource shortage. Not only will networks need the ability to adjust their investments to match demand, but they will also need to consider the availability of resources as part of this investment forecasting.

Networks will also need flexible regulatory mechanisms that allow regulatory allowances to be shifted to when the investment is needed. The current regulatory model provides allowances in five-year investment blocks, built on an assumption that demand growth is well-understood and predictable. The model also provides some flexibility with the ability to request additional allowances for unforeseen large customer projects if specific criteria are meet and the investment is approved by the Commission. However, the ability to access new allowances is limited and the application process is slow.

WELL believes that flexibility is needed to re-sequence programmes between regulatory periods. Section 4.3.1 highlighted that the step change in investment needed to decarbonise Wellington will be sustained across multiple regulatory periods. Given that large subtransmission upgrades have 3-4 year design and build cycles, relatively short and rigid five-year regulatory funding periods may no longer be fit for purpose – longer planning cycles or the ability to re-order work programmes between regulatory periods will be needed to allow networks to efficiently match funding with expenditure. It may be that an ongoing Individual Price Path (IPP) regulatory framework is needed to allow networks to manage the transition of work programmes between regulatory periods.

4.3.5 Considering Long-Term Cost Efficiency

WELL network design considers long-term efficiency and whether making a larger initial investment can provide customers with a lower long-term cost. For example, customers may pay less in the long term if WELL installs larger cables as it replaces ageing assets. While larger cables will provide more capacity than is immediately required and are more expensive than installing lower capacity cables, the incremental cost of sizing the cable for the forecast load growth over the asset's life avoids repeating the expensive civil costs associated with the trenching required to install more capacity at a later date.

Once it becomes necessary to make an investment, careful assessment of how much capacity to install can provide customers with significantly lower prices in the long term. Case Study 6 explores two examples of this.

Case Study 6 – Long term cost efficiency

Table 4-4 compares the long-term cost of replacing two types of assets: a pair of power transformers at a zone substation, and 1 km of high voltage underground cable. Two scenarios are considered: installing smaller capacity assets that will have to be upgraded with more capacity in the future; and installing larger assets with enough capacity to meet all expected demand growth over the life of the asset.

	NPV of Building Additional Capacity Early	NPV of Building Capacity Incrementally	Difference	Difference %
Zone Substation Transformers	$2.9	$4.6	-$1.7	-37%
Underground Cables (1km)	$1.7	$2.3	-$0.6	-24%

Table 4-4 Comparison of Building Capacity Early or Incrementally

The zone substation 'build now' scenario assumes a $3.3m build cost to provide all future capacity requirements, and the 'build later' scenario assumes an initial $2.9m now to meet immediate capacity requirements and a further $3.3m to upgrade the capacity after 15 years.

The underground cable 'build now' scenario assumes a $2m build cost to provide all future capacity requirements, and the 'build later' scenario assumes an initial $1.5m now to meet immediate capacity requirements and a further $1.5m for a capacity top up after 15 years.

The examples show that the most efficient long-term capital investment plan will be dependent on the installation cost of each asset type, specifically whether that initial installation includes a significant cost element that could be avoided in future upgrades by installing more capacity earlier. In these examples, it is more efficient to install larger underground cables and zone substation transformers because future installation costs can be avoided. Future analysis should also consider the value of optionality and the value of not committing too early to one specific way of providing future capacity.

Consideration of long-term cost efficiency will be especially relevant on the Wellington network because a high proportion of the network is underground. Underground equipment has a very high installation component, with civil trenching comprising up to 80% of the asset cost. The relatively small incremental cost of larger cables will mean that in most situations it will be more efficient in the long term to install cables larger enough to meet all future demand increases over the life of the asset.

4.3.6 Resource and Materials Scarcity

The Boston Consulting *'The Future is Electric'* estimates that networks (grid and distribution) will need to invest $100b to provide New Zealand access to the renewable energy it needs to decarbonise. This investment will be at the same time as other countries are also decarbonising and other ageing infrastructure in New Zealand (like water) is replaced.

This step change in work programmes will lead to resource scarcity – both materials and labour. The COVID-19-driven labour shortages highlighted the impact that labour shortages can have on a business's ability to deliver (a decline in productivity of industries that relied on overseas seasonal workers) but also on labour cost (the primary driver behind the country's high inflation in the early 2020's).

Careful planning will be needed to ensure the industry has the labour, expertise and materials available when they are needed to deliver the step change in work programmes. Careful planning will also be needed to ensure the electricity sector can secure resources when there will be many competing interests.

4.3.7 Other Infrastructure Programmes

60% of WELL's network is underground and is often located in the same corridor as other infrastructure assets like potable water, stormwater, and wastewater pipes. Electricity assets sometimes need to be relocated when water assets are replaced, maintained, or repaired. While the current regulatory framework allows the cost of relocating assets to be recovered from water companies, the relocation will still use scarce resources which are needed for the asset replacement and reinforcement programmes.

The Water programmes provide opportunities to share underground civil works costs when electricity services and water assets are in the same corridor. An EDB can lay ducts at the same time as water assets are being upgraded, avoiding having to repeat expensive underground works when the electrical assets need replacing or reinforcement. However, changes are needed to the IMs to allow networks to capitalise underground ducts. Under the current rules, EDBs cannot capitalise the ducts until they can be used which means they will not be able to add the assets on the RAB and receive a return for that investment.

4.4 WELL's Delivery Strategy

WELL has developed a delivery strategy in response to changing distribution services and a step change in its future work programme. The delivery strategy has been developed using a risk analysis framework based on the characteristics of the future investment program established in Sections 4.1 and 4.2 of this chapter. The mitigations to the risk analysis form the bases of the delivery strategy.

The delivery strategy is centred on expanding WELL's outsourced business model by developing a Project Management Office focused on managing the outsourced delivery of large design and build work packages. This approach recognises that:

- The work programme for the next 10 years will focus on large subtransmission and 11kV feeder projects that will need construction organisations experienced in delivering big work packages with large civil elements (Wellington's subtransmission and 11kV networks being predominantly underground).
- There will be cost efficiencies from consolidating work packages into larger programmes (as opposed to having to manage multiple small projects). WELL is cognisant that customers and the regulator on their behalf, will continue to demand that EDBs provide efficient services.
- Large new delivery capability is needed and consolidating work packages will allow WELL to attract larger civil and electrical organisations (possibly international companies) into the region.
- WELL will still need to maintain its current delivery capability to continue to maintain the existing network and to ensure it meets its regulatory quality targets. WELL's current delivery functions must not be distracted by the step change in network growth.

To support the new delivery function, the delivery strategy includes work streams to develop WELL's internal capability focused on designing a network blueprint that will provide efficient and reliable distribution services.

This includes a network design that delivers customer reliability expectations. The overarching blueprint will provide a robust backbone that the work programme can be packaged and delivered around.

4.4.1 Summary of the Characteristics of the Future Investment Programme

New drivers of demand and changing distribution services means that EDBs will have to make a step change in investment. The characteristics of the future investment programme were discussed in the previous sections and are summarised as:

- **Significant LV network investment:** Investment in LV visibility will be needed immediately to enable the network planning team to assess whether customers can safely and securely connect DER. LV management will be needed to forecast constraints, incorporate and value flexibility services, and coordinate demand management responses (Section 4.2.2).

- **Need to directly manage the connection and operation of large DER:** The development of flexibility services to the scale needed will take time and there are a number of early steps needed to ensure networks can accommodate large DER devices while maintaining network security. Large DER must apply to connect to a network (to ensure capacity is available), and be capable of being remotely managed and participating in a flexibility service (Section 4.2.2).

- **Opportunities for flexibility services:** Third-party studies and WELL's modelling show that flexibility services have the potential to be valuable, by supplying some of the demand increase from previously unused capacity in the network's off-peak periods. Flexibility services provide an important opportunity to spread out the front-loaded investment programme, providing relief to scarce delivery resources (Section 4.2.2).

- **Ensuring distribution services are what customers want:** The services customers want will continue to evolve and change with customer preference. Networks will need to decide how they will communicate with customers to ensure they continue to provide services customers want at a price they are willing to pay for. Networks will need to develop a closer relationship with customers to ensure services are aligned with customer needs (Sections 4.2.3 and 4.2.4).

- **A material step change in investment, significantly larger than the historic average:** WELL is forecasting a 98% increase in maximum demand on the Wellington network by 2053. The network does not have sufficient spare capacity to meet this demand increase, and new capacity will need to be built. The annual investment required increases from a recent average of $42m p.a. to $90m p.a. – a material step change from business-as-usual investment (Sections 4.2.1 and 4.3.1).

- **An investment programme that is sustained across multiple regulatory periods:** Like other EDBs, WELL's investment programme will be required to deliver new capabilities and continue to replace ageing assets to maintain network reliability, security, and power quality. Unlike past step changes in investment that could be ringfenced into a single CPP, the size and timing of future ERP-related investment will require a sustained increase in investment across multiple regulatory periods (Section 4.3.1).

- **The investment programme is front-loaded:** The investment is front-loaded with the highest investment occurring in the first 10 years. This is because reinforcement of the 33kV subtransmission network will be required, resulting in the need to deliver a number of large, expensive projects over the next ten years, whereas 11 kV and LV reinforcement can be delivered throughout the period with smaller projects targeted at specific constraints as they arise (Section 4.3.1).

- **The majority of expenditure will be from the reinforcement of the existing network:** 60% of WELL's forecast investment over the next 30 years is expected to be driven by the need to increase the network's capacity. Brownfield network reinforcement is more expensive than greenfield development because of the complexity of working around existing infrastructure (Section 4.3.1).

- **Rapidly increasing costs:** The step change in investment across most networks and in other infrastructure industries will create resourcing and materials scarcity. This is likely to continue to drive higher inflation in the electricity industry than what is captured in the general inflationary measures. Currently, these costs are not captured in regulatory allowances (Section 4.3.3).

- **Uncertain investment timing:** While EDBs can be confident that a significant increase in investment will be needed, the sequencing of the work programmes is uncertain. Faster than expected demand will mean that EDBs will have to bring forward work programmes (Section 4.3.4).

- **Rapidly changing customer needs:** Some of the underlying drivers of changing demand could change demand quickly with little lead time for networks to adjust their investment forecasts and regulatory price paths. Significant unforeseen changes in investment requirements could occur within a regulatory period (Section 4.3.4).

- **High value in flexible investment timing:** The costs to customers of building too early or building too late are significant. There is value in EDBs being able to flex their investment programmes to match changes in demand (Section 4.3.4).

- **Opportunities to build capacity early when it is efficient:** Some assets have high installation costs which will mean it is efficient to install enough capacity initially to meet all growth over the life of the asset, rather than incrementally adding capacity when it is needed. There may be long-term savings for customers if capital expenditure programmes can consider dynamic efficiency (Section 4.3.5).

- **Uncertain resource availability:** Electrification is a global challenge, which is resulting in strong competition for scarce resources both regionally and internationally. The availability of skilled people and materials may impact the timing of investment delivery, as EDBs may need the ability to shift when they can build new assets to when resources are available (Sections 4.3.4 and 4.3.6).

WELL has developed a delivery strategy in response to these key characteristics of the investment programme.

4.4.2 Developing a Delivery Strategy

WELL's approach to delivering the climate change driven demand increase, is a combination of better utilisation of the existing distribution network, and building more capacity to meet any residual demand.

Table 4-5 provides a risk analysis for each investment characteristic that poses a risk and the delivery workstreams that are being implemented in response. The investment characteristics that create opportunities have been used to inform the delivery response. The risk analysis reflects the change from a 'business as usual' operating environment focused on maintaining the existing network and cost efficiency, to delivering a step change in investment and new distribution services. The delivery workstreams focus on the new processes and capabilities needed to double the size of the work programme and build and incorporate non-wire solutions into the network.

Investment programme characteristic	Risks/opportunity	Mitigation (delivery work programme)
Significant LV network investment	Demand uncertainty – can't accurately forecast LV level demand Uncertainty LV capacity and security Uncertain LV reinforcement requirements	Develop a regular supply of customer data Develop LV management capability Develop LV refinement investment programme
Need to directly manage the connection and operation of large DER	The unmanaged connection of DER will mean that EDBs may not be able to maintain network security Flexibility services won't be available in time to provide a solution. Policy changes are unlikely to be made fast enough to support the managed connection of large DER	Customer education to shift electricity use away from peak periods. Implement 'pre-flexibility' steps to ensure Large DER must apply to connect to a network (to ensure capacity is available), and be capable of being remotely managed and participating in a flexibility service Implement changes via distribution connection codes if policy changes can't be made fast enough
Ensuring distribution services are what customers want	Customers cannot use their devices and appliances as they want Customers unhappy with service levels and look for alternatives – stranded asset risk	Develop a customer engagement strategy Develop a customer consultation framework to support future price path applications.

Investment programme characteristic	Risks/opportunity	Mitigation (delivery work programme)
Material step change, significantly larger than the historic average	Design and delivery capability are aligned to current BAU operations, and not suited to supporting a large network reinforcement programme. Resource & materials availability Allowance availability	Develop a master network design which will provide the required capacity and security. Refined capital expenditure programme that coordinates asset health and new capacity requirements. Refine the regulatory model to ensure allowances will be available when they are needed. Incorporate dynamic efficiency test into capital works planning – design a work programme that provides the lowest long-term cost Develop an industry people and materials resource plan and coordinate training programmes and supply chains. Develop a PMO function to manage the outsourced delivery of large work packages
Sustained across multiple regulatory periods	The regulatory framework is not designed for step-change investments that are sustained across multiple regulatory periods	Refine regulatory framework to support sustained levels of investment. Develop an industry people and materials resource plan and coordinate training programmes and supply chains. Develop the internal capability and support capability to support the programme
Limited existing spare capacity resulting in front-loaded Investment	Not able to deliver the new capacity requirements fast enough, resulting in an inability to maintain network security. Resource & materials availability Funding & allowance availability	Develop flexibility services to delay network reinforcement wherever possible, spreading out/flattening the investment profile Develop an industry people and materials resource plan and coordinate training programmes and supply chains.
Growth will also come from existing connections, requiring reinforcement of the existing network	More complex and expensive network reinforcement Underground network in close proximity to water assets	Co-ordinate work programmes with other infrastructure providers Develop an industry people and materials resource plan and coordinate training programmes and supply chains.

Investment programme characteristic	Risks/opportunity	Mitigation (delivery work programme)
Unaffordable distribution services	While household energy costs should decrease, other cost increases (inflation, other infrastructure costs, insurance etc) could make the required investment in electricity infrastructure unaffordable Lower household energy costs are only available to those who can afford expensive electric appliances – which slows ERP response and increase the equity gap	Develop flexibility services – keep prices as low as possible. Develop education tools to inform customers about how to use distribution services efficiently (energy saving ideas, participation in flexibility services etc). Develop dynamic efficient tests for CAPEX planning. Lobby for financial support to assist those in energy hardship to electricity their fossil-fuelled devices.
Uncertain and quickly changing investment timing	New capacity may be needed sooner than expected Risk of building too early and customers paying more Regulatory allowances not available when needed	Continue to refine and update the demand growth models. Incorporate the impact at an LV network level. Develop a flexibility response to help manage demand uncertainty (building a buffer if network reinforcement is needed). Develop regulatory flexibility that allowances to be shifted to when they are needed.
Uncertain resource availability	Inability to build new capacity when it is needed – delaying investments and impacting network security	Develop an industry people and materials resource plan and coordinate training programmes and supply chains.
Rapidly increasing costs	Resources and materials scarcity increasing costs at a rate faster than the inflation adjustments in the regulatory allowances.	Real cost forecasts include current materials and labour costs. Ensure the regulatory allowances capture industry-specific inflation.
High value in being able to closely match capacity and demand	Uncertainty growth rates make matching capacity and demand difficult. Regulatory allowances and IRIS incentives penalise/reward networks adjusting spend profiles in response to uncertain demand (rather than for cost efficiency)	Develop a flexibility response to help manage demand uncertainty (building a buffer if network reinforcement is needed). Develop regulatory flexibility that allowances to be shifted to when they are needed.

Table 4-5 Future Investment Programme Risks, Opportunities, and Mitigations

The risk analysis resulted in eight key workstreams. The workstreams focus on providing the capacity needed to deliver the step change in investment. The workstreams reflect the move away from business-as-usual operations. The delivery workstreams have been summarised in Table 4-6.

Delivery Work Programme	How	2024 AMP Reference
Continue to refine our demand growth modelling: providing better investment certainty by improving the accuracy of our demand forecast and our future capacity requirements	1. Continue to refine and update growth models with actual growth and refinements of national ERP responses. 2. Develop an LV growth model using findings of the LV reinforcement study and LV management technology trials. 3. Develop a scenario model to understand the impact of uncertain growth rates	Section 4.2 provides an overview of current forecasts. Section 9 provides detailed demand forecasts to zone substation level. Section 9.7 provides the results of the LV Reinforcement study.
Continue to refine our future investment programme: ensuring the network provides the expected capacity and security by building to a network masterplan. Develop investment models to calculate when to build new capacity – build capacity yearly or wait until it is needed	1. Master network design and standards to guide the long-term network development 2. Include new growth forecasts into the network growth AMP process and AMP schedule 3. Include the impact of combing asset replacement and reinforcement programmes into asset replacement schedules 4. Develop and incorporate an LV reinforming investment programme (following the development of an LV growth model and capacity study) 5. Develop and incorporate dynamic efficiency investment tests into investment planning (invest in new capacity now or wait until it is needed). 6. Develop scenario modelling, demonstrating how investment profiles will change in response to different growth profiles	Section 4.3 provides an overview of the current long-term investment programme. Sections 8 and 9 provide investment details.
Fit for purpose services: Ensure we continue to provide distribution services customers want, at a price they are prepared to pay	1. Develop a customer engagement strategy that will ensure we are delivering fit-for-purpose services 2. Implement customer engagement channels 3. Customer education tool to assist customers to use distribution services efficiently 4. Support the industry in promoting participation in flexibility services	Section 6.5.9 discusses the draft Customer Engagement Strategy.

Delivery Work Programme	How	2024 AMP Reference
LV visibility and management: Develop the ability to manage the connection of DER of the LV network and incorporate flexibility services	1. Secure customer data is needed to provide LV visibility (both access to data and funding to purchase it). 2. Develop a long-term development path for the development of an LV management capability – recognising that not all of the capability will be needed immediately. 3. Test, trial and develop the technology to manage the LV network – including connection assessments, constraint forecasting and integrating demand management.	Section **10.3.1** 10.3.2 provides an overview of the trial.
Develop flexibility services: to assist in uncertain demand, spread out the investment programme, and lower prices.	1. Implement 'pre-flexibility' steps to ensure that large DER must apply to connect to a network (to ensure capacity is available), and be capable of being remotely managed and participating in a flexibility service 2. Strong price signals and customer education to shift electricity use away from peak demand periods. 3. Continue to work with the industry to implement the flexibility service building blocks identified by the EV Connect Roadmap 4. Implement flexibility trials that have a runway to a mass market service. 5. Develop internal capacity to offer, incorporate and manage flexibility services. 6.	Section 10.3.4 provides a progress update on each development programme.
Build new delivery capability and capacity: to deliver large reinforcement and asset replacement programmes.	1. Develop a Project Management Office to manage the outsourced design and build of large investment programmes. 2. Develop key suppliers with the scale needed to deliver the large work packages. 3. Develop internal support functions	Section 10.3.3.1 provides an overview of how the PMO will function and the advantages it will provide.

Delivery Work Programme	How	2024 AMP Reference
Co-ordinated resourcing development and materials supply chain: Develop an industry people and materials resource plan and coordinate training programmes and supply chains to ensure resources are available and can be shifted to where they are needed.	1. Develop/review design standards to use standard equipment types 2. Develop a materials plan, highlighting long lead items. Align procurement plans with other networks and consider opportunities for high volume discounts or to secure supply 3. Work with ENA and other networks to consider future national resourcing requirements. Consider whether the industry needs to promote trainees	Section 10.3.3.3 provides an overview of WELL's approach to
Regulatory flexibility: Networks have the allowances needed to deliver future distribution services at an efficient price	1. Refine the regulatory model to ensure allowances are available for the step change in investment. 2. Include uncertainty mechanisms to allow the provision of when allowances are provided to adjust to changes in demand growth. 3. Provide allowances or the substitution for capital expenditure allowances, to fund the purchase of flexibility services. 4. Fund the innovation needed to develop the capability to offer and use flexibility services. 5. Allow work programmes to bridge regulatory years, removing artificial restrictions on when programmes can be implemented and delays in waiting for the next period's regulatory allowances to be approved. 6. Ensuring allowances are capturing new costs that networks can't avoid – ensuring that networks can make a fair return on the investment they are expected to make in the networks.	Section 10.3.1 summaries the changes needed to the regulatory framework

Table 4-6 Workstream Delivery

As highlighted earlier, networks have developed their initial thinking on the ERP over a relatively short period of time. WELL will continue to evolve its delivery work programme and it will change as thinking is tested and refined. Updates to the delivery strategy will be provided as it develops.

Section 5

Frameworks

(Asset Management, Safety, and Risk)

5 Asset Management, Safety and Risk Frameworks

This section describes WELL's asset management frameworks, its approach to health, safety and quality, and its risk management processes and governance.

WELL's asset management framework is aligned with the company's vision, mission, corporate strategy and objectives and is reflected in this AMP. The framework reflects the principles of the international standard ISO 55001. The key components of the framework are shown in Figure 5-1.

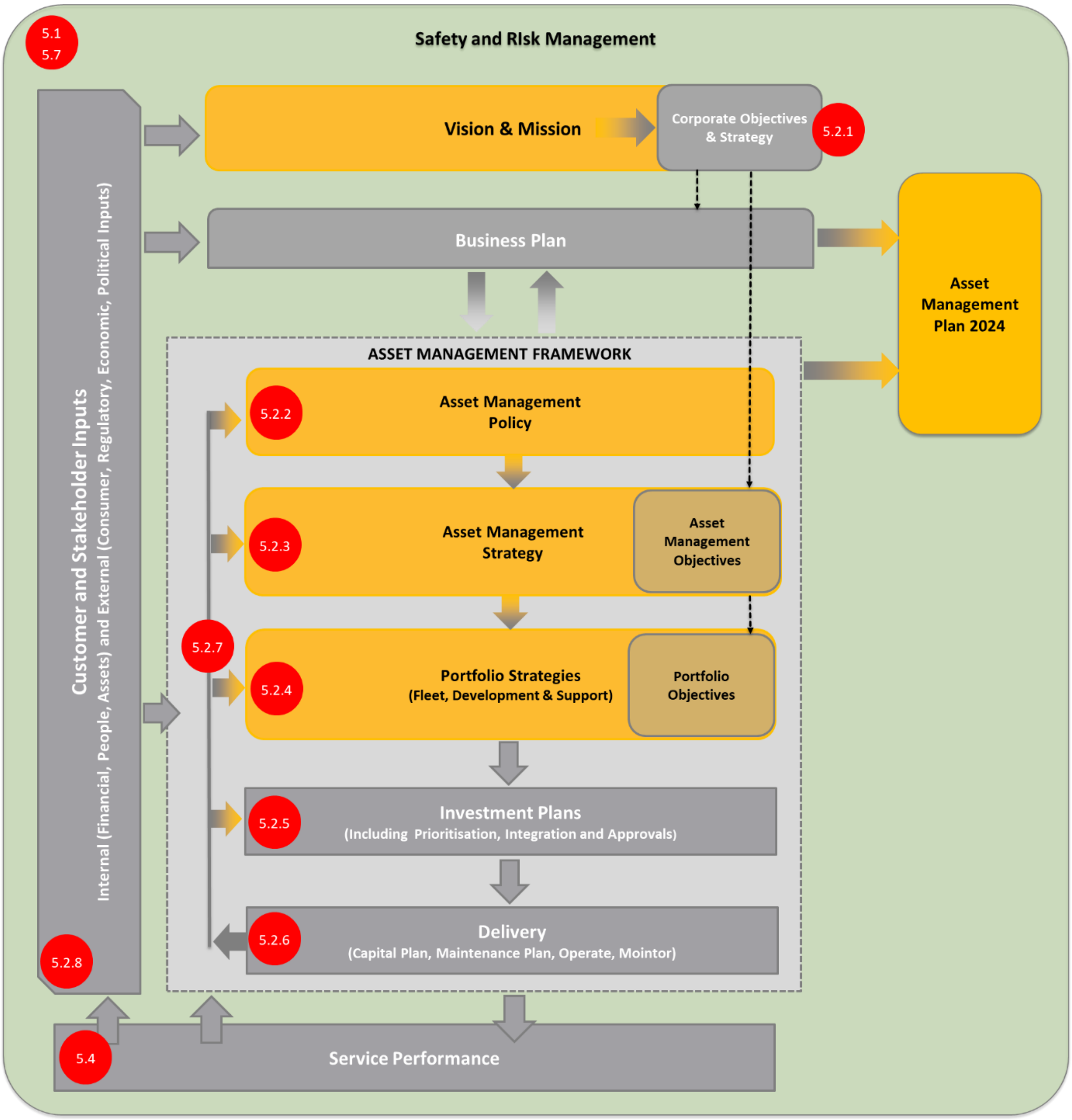

Figure 5-1 Asset Management Framework

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

In summary the section covers:

- Quality, safety and the environment (QSE);
- 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); and
- Risk management.

5.1 Quality, Safety, and the Environment (QSE)

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

- Members of the public are not harmed by the operation, maintenance, and improvement of WELL's assets;
- All employees and contractors undertake their work in a safe environment using safe work practices;
- The wellbeing (physical and mental) of staff and field workers is a key focus;
- Controls, such as policies, plans, and competencies are effective for minimising impacts on the environment;
- Processes such as audit and review procedures are in place to ensure high-quality outcomes are consistently achieved; and
- Continuous improvement is a key goal.

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

In accordance with WELL's mission, health and safety is given top priority and is a core business value. A Board Health and Safety Committee meets regularly to be updated on metrics, workplace safety and initiatives, issues, and to provide guidance to management. As illustrated in Figure 5-2, a formalised safety leadership structure is in place to help ensure that health and safety leadership is provided throughout the business.

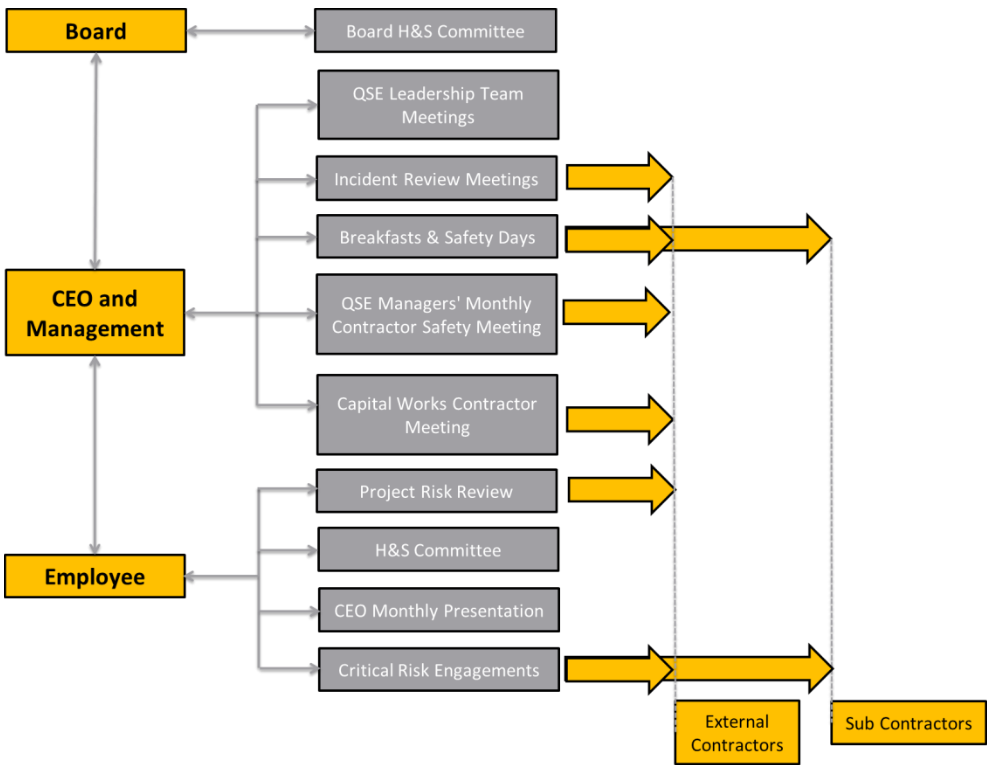

Figure 5-2 WELL's Safety Leadership Structure

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

Similarly, quality and environmental outcomes are managed by WELL via consultation, cooperation and coordination. All employees and contractors are required to:

- Take all reasonable steps to ensure that business activities provide an outcome that minimises environmental impacts and promotes a sustainable environment for future generations;
- Take all reasonable steps to ensure the delivery of goods, products and services are to an acceptable standard and meet the quality expectations of the business; and
- Identify and report any defects or non-conformances to enable improvement in the systems or performance to maintain quality outcomes.

WELL's QSE outcomes and processes are discussed in more detail below. The associated performance objectives and measures are described in Section 6.

5.1.1 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 with the Health and Safety at Work Act 2015.

The Health and Safety at Work Act 2015 (HSW Act) came into effect in 2016. Consistent with the HSW Act, WELL continues to develop closer relationships with other organisations and stakeholders where an interface with network assets exists. The HSW Act requires a greater level of consultation, cooperation, and coordination in relation to health and safety duties and issues. This brought about several 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 purpose 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.

5.1.2 Public Safety Management Systems (PSMS)

WELL has a Public Safety Management System (PSMS) framework, built on policies, procedures and guidelines relevant to the safe design and management of the assets. The PSMS helps ensure that assets installed in public areas do not pose a risk to public safety. The PSMS meets the compliance requirement for electricity distributors to implement and maintain a safety management system for public safety set out in Regulations 47 and 48 of the Electricity (Safety) Regulations 2010.

The PSMS also meets the requirements of NZS 7901:2008 Electricity and Gas Industries - Safety Management Systems for Public Safety. The certification body Telarc last recertified WELL against the requirements of NZS 7901 in 2021 and confirmed that WELL was compliant with regulatory requirements, the next recertification audit is scheduled for 2024. Annual surveillance audits are conducted by Telarc between recertification audits.

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.

5.1.2.1 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 is 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.

5.1.2.2 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 2021 relating to vegetation management, major event preparedness, and safety in lines down situations.

5.1.2.3 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.

5.1.2.4 Contractors' Safety Booklet

WELL has produced a safety publication targeted at civil contractors and those working near, but not accessing, the WELL network. This booklet *"We* All Need to Work Safely"*, last revised in February 2020, is handed to those attending safety workshops and in mailouts to various contracting sectors that interface with the network.

5.1.2.5 Information 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
- Private and Strategic Cable Locations[22]
- Close Approach requests
- Standovers
- High Load Permits
- High Load Escorts

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

[22] Other cable locations are now provided via a direct service by cable location companies.

5.1.3 Workplace Safety and Initiatives

As WELL has the following workplace safety initiatives in place.

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

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

5.1.3.2 Safety Breakfasts

WELL regularly arranges safety breakfasts for all its external contractors. These breakfasts aim 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.

5.1.3.3 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. These seminars aim to reinforce WELL's desired behaviours through direct interface with keynote speakers and other subject matter experts.

5.1.3.4 Critical Risk Engagements

All WELL staff undertake engagement visits to sites where contractors are working on the network. The engagement visits are used to confirm understanding and implementation of corrective actions and to discuss safety systems and opportunities for improvement.

5.1.3.5 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 by providing, for example:

- CPR/First Aid refresher sessions every six months;
- Work Type Competency training;
- Restricted area access training;
- Defensive driving training; and
- Basic traffic control management.

5.1.3.6 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 from occurring or reoccurring, and to use lessons learnt for continuous improvement.

5.1.3.7 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.

5.1.4 Environmental, Social, and Governance (ESG)

WELL's Board of Directors established an ESG Committee in 2022 that aims to assist the Board in fulfilling its oversight responsibilities with respect to:

- WELL's strategy in relation to ESG, including the future development of strategy, policy and objectives as the external ESG business environment continues to evolve;
- Ensuring that WELL has appropriate targets and resources in place to ensure effective delivery of key ESG-based commitments;
- Oversight of the reporting and any assurance of performance against ESG targets on a consolidated basis; and
- Oversight of governance as it relates to WELL's strategy in relation to Environmental and Social policy and performance.

WELL's first ESG Strategy was approved by the Board in February 2023. WELL aims to integrate sustainability into how it manages its impact on the economy, environment, and people, and has set an overarching goal of *"Empowering a resilient and sustainable future for Wellington."* To reach this goal WELL has set targets in emissions reductions, gender diversity, waste minimisation, community and staff ESG education, and leading initiatives to support the intensification of renewable energy.

5.2 Asset Management Framework

5.2.1 Corporate Objectives

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

5.2.2 Asset Management Policy

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

It aligns with the company's mission to "own and operate a sustainably profitable electricity distribution business which provides a safe, reliable, cost-effective and high-quality delivery system to our customers".

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

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

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

- Has a strong safety focus regarding its employees, contractors and members of the public;

- Aligns with corporate objectives and plans;
- Is founded on customer service level expectations and engages stakeholders where appropriate on asset-related activities;
- Stays up to date with national and international asset management standards, trends and best practices;
- Complies with all applicable regulatory and statutory requirements;
- Aligns with the risk management framework;
- Assists with the development of staff capabilities and the engagement of external resources when required to continually improve asset management capability; and
- Provides a suitable long-term return on investment for shareholders.

5.2.3 Asset Management Strategy and Objectives

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

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

The Asset Management Strategy summarises the objectives and strategies in each of these five priority areas. The first four priority areas relate to aspects of WELL's performance. The fifth priority area relates specifically to asset management capability, which supports the other objectives. Sections 6 to 8 provide more detail on specific asset management objectives and strategies associated with these priority areas.

5.2.4 Portfolio Strategies

Portfolio strategies translate the Asset Management Strategy into specific strategies for each portfolio, link back to the objectives in the Asset Management Strategy, and detail any fleet-specific objectives. These portfolio strategies include asset fleet strategies, network development strategies, emerging technology, support systems, resilience, and customer-initiated projects and relocations, which are discussed in Sections 8 to 13 respectively. Each strategy is used to develop Network Standards, work plans and programmes which include the activities and budgets presented in the 10-year AMP and five-year business plan.

5.2.5 Investment Planning

WELL's investment plans are developed from the portfolio strategies. Investment planning includes integration, prioritisation and approval processes to ensure prudent financial investment. Investment planning is discussed further in Section 5.3.

5.2.6 Delivery

There are two components to delivery: delivery of the investment plans and management of the network in real-time. The delivery of investment plans to meet the target customer service levels is discussed in Section 5.3.

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

5.2.7 Internal Feedback Loops

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

5.2.8 Stakeholder and Customer Inputs

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

5.3 The Investment Selection Process

The investment selection process has five generalised stages, as illustrated in Figure 5-3.

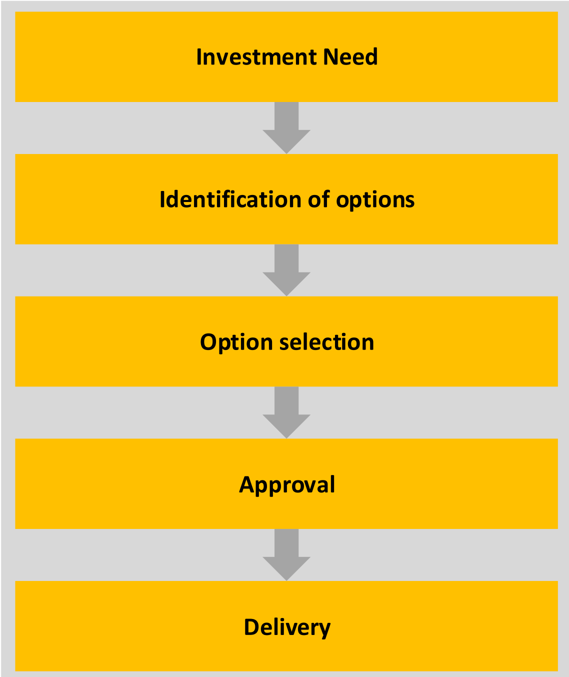

Figure 5-3 Investment Selection Process

5.3.1 Need Identification

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

5.3.1.1 Risk-based Approach

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

- Proactively: Reducing the probability of asset failure by meeting security of supply criteria standards, capital and maintenance work programmes, enhanced working practices and the development of fleet strategies. The development of these strategies includes root cause analysis from the growing database of asset failure information, and predicts future corrective maintenance expenditure over time; and

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

The risk of an asset failure is a combination of the likelihood of failure (largely determined by the condition of the asset) and the consequences of failure (determined by the immediate safety impact of the failure, the magnitude of any supply interruptions, any environmental consequences, the repair or replacement time, and the extent of any reduction in network operating security while the asset is being repaired). Assessment of this risk assists the process of deciding whether to phase out an asset through a planned replacement programme or to allow it to continue in service, supported if necessary by additional inspection and preventative maintenance activities.

5.3.1.2 Prioritisation of Projects

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

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

Non-discretionary projects include:

(i) HSE and Legal Compliance. WELL's top priority is to operate a safe and reliable network and thus projects needed to address safety concerns and/or meet legal requirements are given high priority.

(ii) Customer-initiated Projects. Provided WELL has received sufficient advanced notice, it will give appropriate priority to planning, designing and implementing projects required to meet the needs of commercial and industrial customers.

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

5.3.2 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 customer in the case of residential/commercial solar DG, or by WELL in the case of grid-scale DG and/or battery storage;
- Repair or refurbishment of existing distribution assets;
- Replacement with new assets; and
- An extension or upgrade of the existing distribution network.

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

5.3.3 Option Selection Process

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

The process is as follows:

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

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

3. 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.

5.3.4 Investment Approval

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

5.4 Asset Management Delivery

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

5.4.1 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, Connetics, Downer, Electrix, and Ventia;

- Vegetation management – Treescape; and

- Contact centre – Telnet.

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

The services provided are described in further detail below.

5.4.1.1 Fault Response, Maintenance and Minor Capital Works

Northpower Ltd has been WELL's primary field service provider responsible for fault response and maintenance since 2011. In 2018 WELL ran a contestable process for a new field services contract. Northpower was successful and was contracted as the field services provider under a new Field Services Agreement (FSA) through to 2023. WELL extended this contract in 2022, with the existing contract to remain in place until the end of 2024.

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

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

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

5.4.1.2 Contestable Capital Works Projects

Contestable capital works include:

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

Contestable capital works projects are competitively tendered. They are delivered under either independent contractor agreements (ICAs) or the FSA if Northpower is the successful tenderer. These agreements outline the terms and performance requirements the work is to be completed under and include KPIs or KRAs, defects liability periods, insurance and liability provisions, and also reflect the requirements of the HSW Act. All contracts are managed on an individual basis and include structured reporting and close-out processes including field auditing during the 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.

5.4.1.3 Vegetation Management

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

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

5.4.1.4 Contact Centre

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

5.5 Asset Management Documentation and Control

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

- High-level policy documents – which define how the company will approach the management of its assets;
- Asset fleet strategies – asset maintenance, lifecycle management and renewal strategies for a range of asset groups, from subtransmission cables and power transformers to the various pole types and LV installations;
- Network development and reinforcement plans – providing a 30-year plan of forecasted load growth, potential constraints and strategies to mitigate in conjunction with asset renewal and reliability improvement programmes;
- Technical standards for procurement, construction, maintenance and operation of network assets;
- Network guidelines – provide directions and procedures on the construction, maintenance and operation of network assets and processes to achieve a desired outcome; and
- Network instructions – provide further instructions on the construction, maintenance and operation of network assets and processes.

All documents such as policies, specifications, drawings, operations and maintenance standards, and guidelines follow the structure of the controlled document process, with a formalised review and approval process for new and substantially revised documents. The documents are made available via intranets and extranets to both internal users and external contractors and consultants. Generally, documents are intended to be reviewed every three years, however some documents, due to their nature or criticality to business function, are subject to more frequent reviews.

5.6 Asset Management Maturity Assessment Tool (AMMAT)

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

- Asset strategy and delivery;
- Communication and participation;
- Competency and training;
- Documentation, controls, and reviews;

- Structure, capability and authority; and
- Systems, integration and information management.

WELL's Asset Management Maturity Assessment is provided in Appendix C. Figure 5-4 provides a summary of the results.

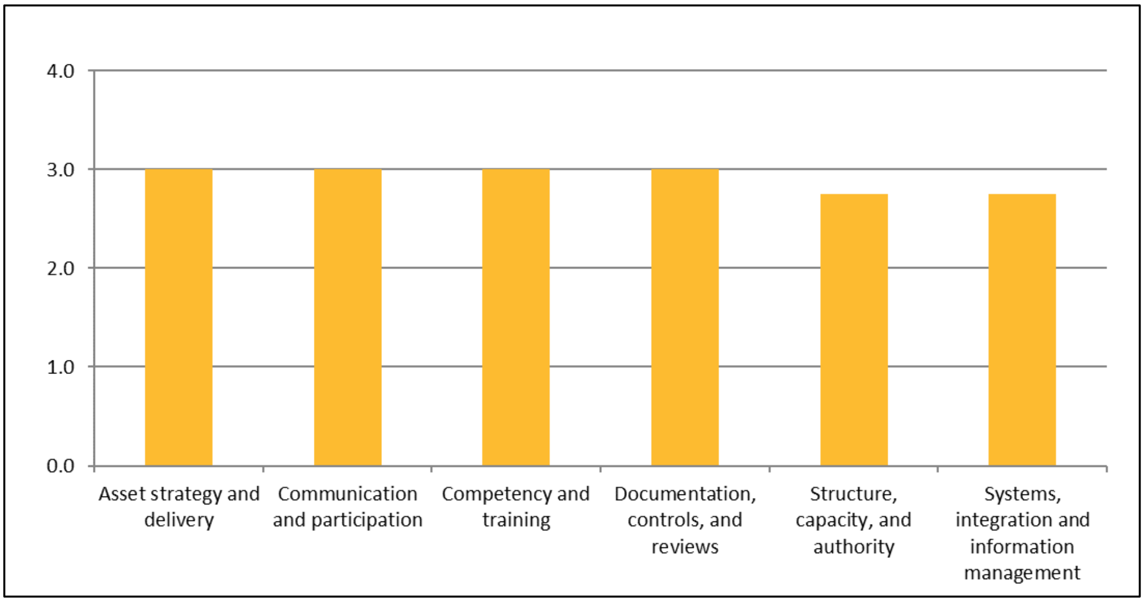

Figure 5-4 Summary of the Maturity Assessment 2023

The areas of improvement identified in the AMMAT relate to the asset management resources needed to support the step change in demand required by the ERP, and the need to identify the related additional asset management information system requirements. These items are discussed in Section 10.3.2 and Section 10.3.3.

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.

5.7 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 for managing risk, which is applied to all business activities, including policy development and business planning. WELL's risk management framework is discussed in Section 5.7.2.

Risk management is an integral part of good asset management practice. WELL's approach to managing asset-specific risks is discussed in Section 8.

5.7.1 Risk Management Accountabilities

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

The CEO is accountable for the performance of the business and as such the effectiveness of the controls being employed to manage the risk. While the CEO is held accountable by the Board, the management team has assigned responsibilities for ensuring controls are implemented and well-managed so that risks are reduced to an acceptable level. The responsibility for controls is assigned to managers and bi-annually reviewed to ensure they remain relevant and that the risk environment has been assessed for new risks or changes to the risk profile. Some of the key controls are listed in Section 5.8.3.

5.7.2 Risk Management Framework

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

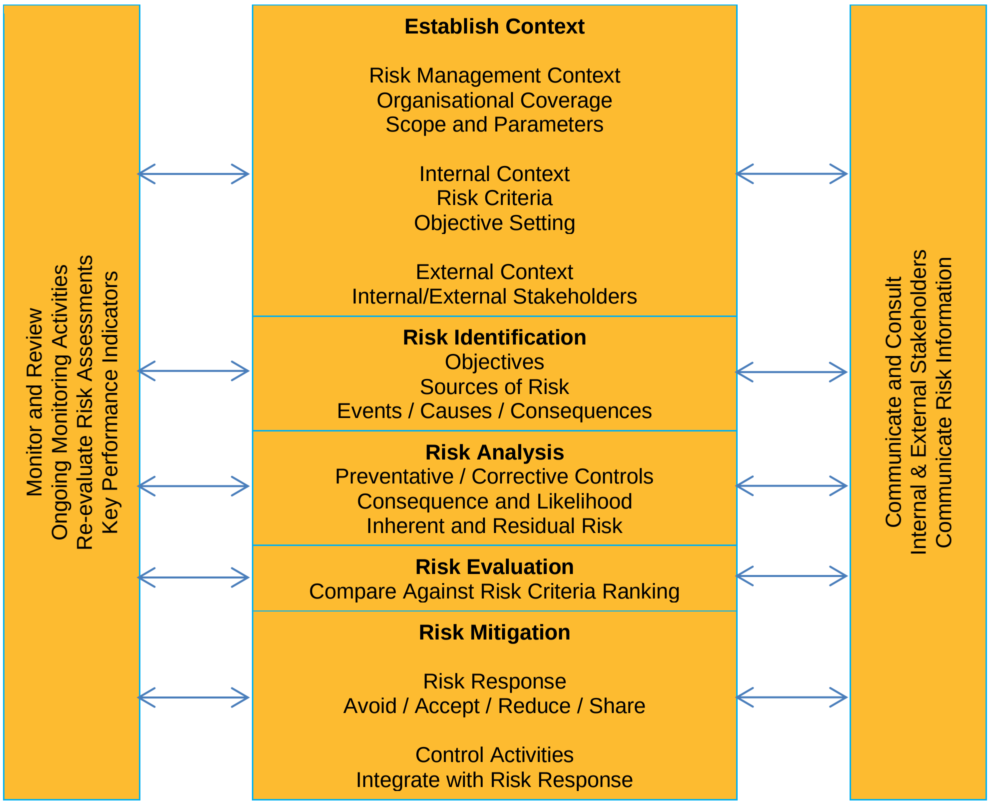

Figure 5-5 WELL's Risk Management Process

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

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

Risk Identification. Risks are identified through operational and managerial processes. WELL has grouped its risk into seven categories. Section 5.7.3 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). The risk rating is plotted on a risk chart with its likelihood score on the y-axis and overall consequence on the x-axis, with an example of a qualitative risk matrix shown in Figure 5-6.

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 5-6 Qualitative Risk Matrix

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

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

5.7.3 Key Business Risks and Controls

Rankings of risk events and control effectiveness were updated in December 2022, identifying no current extreme residual risks and only one high residual risk.

In total, 46 business risks were assessed by WELL. Table 5-1 shows the 10 highest risks ranked according to their residual ratings, and then by their inherent risk ratings.

	Event	Inherent Rating	Residual Rating
1	Catastrophic earthquake and/or Tsunami that causes significant damage to Company assets.	High	High
2	A health and safety incident that affects one or more employees, contractors or visitors while performing work or visiting the Business' properties, assets or worksites.	High	Medium
3	Non-optimum starting price adjustment.	High	Medium
4	Exploitation of IT security.	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 Electricity Act and Regulations.	High	Medium
8	Non-compliance with the Health and Safety at Work Act 2015.	High	Medium
9	Inadequate management and/or supervision of contracted (i.e. outsourced) activities (including contractor resources).	High	Medium
10	Mismanagement of a crisis and emergency affecting the network.	High	Medium

Table 5-1 Summary of 10 Highest Business Risks

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

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

5.7.3.1 Insurable Risks and Insurance Premiums

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

The balance (85% by replacement value) of WELL's network is not insured. As such, the customer retains the risk on the uninsured portion of the network. WELL would have to apply for a CPP following a significant event to request additional funding (and an associated price increase) to repair the network. WELL does not insure its subtransmission and distribution assets as insurance cover for these types of assets (poles, cables, wires etc.) is currently only available from a small number of global reinsurers, is very expensive, has high deductibles, and typically excludes damage from windstorm events.

Illustrating this by way of example, if WELL were to insure poles, cables, and wire assets with a policy limit of $500 million, it would need to pay a 10% deductible of $50 million before any insurance payments would be provided. In addition, the annual insurance premium for such cover is expected to exceed $50 million, which has increased recently in line with other general insurance costs. This is not considered economic. Ex-post recovery of the full costs is therefore the regulatory recovery mechanism for managing this risk.

5.7.3.2 Insurance Cover

WELL renews its insurance 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, electromagnetic radiation, financial loss (failure to supply), and professional indemnity and is renewed annually as at 30 September.

Section 6

Service Levels

6 Service Levels

WELL is committed to operating a sustainably profitable electricity distribution business which provides customers 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 performance targets for these areas include:

- Service levels which retailers apply on behalf of customers. These targets reflect the service levels outlined in the current Use of Network agreements with retailers;
- Reliability targets are set as part of the price/quality regulation under Part 4 of the Commerce Act 1986; and
- WELL's service levels are used to measure performance against its Mission Statement.

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

6.1 Safety Performance Service Levels

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

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

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

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

- Incident, near miss, and hazard observation reporting;
- Corrective actions from site visits closed;

- Lost Time Injury Frequency Rate (LTIFR), and
- Total Notifiable Event Frequency Rate (TNEFR).

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

6.1.1 Lost Time Injury Frequency Rate

WELL's staff and contractors recorded two Lost Time Injuries (LTI) incidents in the industry reporting year ending June 2023. This resulted in an LTIFR for that period of 2.61 per million hours worked and a two-year rolling average of 2.59 per million hours worked. The trend in LTIFR is shown in Figure 6-1.

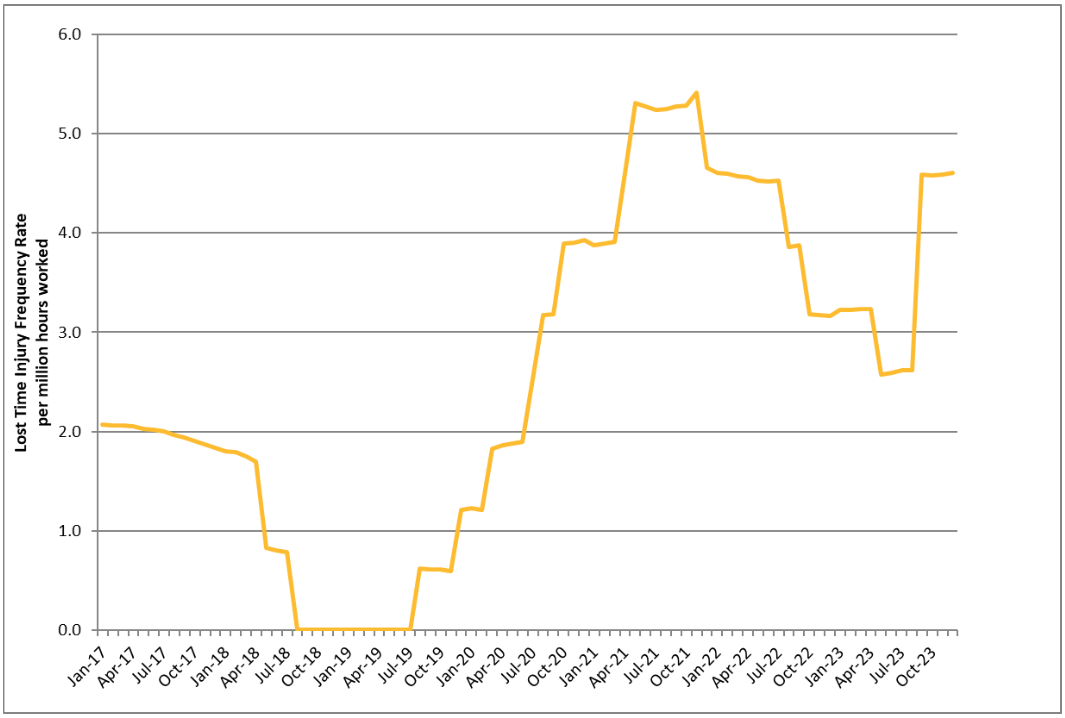

Figure 6-1 Lost Time Injury Frequency Rate (24-month Moving Average)

WELL is actively monitoring the trends in LTI which are primarily lower severity, non-electrical, soft tissue injuries in an ageing workforce requiring time off work for recuperation. WELL is aware of the balance between focusing on network-related critical risks and non-network-related risks and is actively working with service providers to ensure a balance is achieved.

6.1.1.1 Planning Period Target

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

6.1.2 Total Notifiable Event Frequency Rate

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

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

WELL's staff and contractors recorded two Notifiable Events in 2023. This resulted in a 2023 TNEFR of 2.67 per million hours worked and a two-year rolling average of 1.32.

6.1.2.1 Planning Period Target

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

6.1.3 Incident and Near Miss Reporting

During 2023 WELL continued to implement initiatives aimed at increasing reporting rates of hazard observations and near miss events. Increased reporting is a measure of a mature safety culture and allows for continuous improvement from small incidents which in turn reduces the likelihood of serious events.

Total event reporting in 2023 was 420 events reported. Approximately 99% of all reported events were classified as minor, 1.2% were classified as moderate, whilst 0% were of a serious nature. The total number of proactive reports received during 2023 was 99. These 99 are further broken down into five near miss events and 94 hazard observation reports.

Gathering hazard observation data allows WELL to both identify potential sources of harm to workers and the public and to identify emerging trends prior to any harm occurring. It allows WELL to have confidence that outsourced service providers are assessing work sites under their control for any unforeseen locality-introduced sources of harm which have not been identified during works planning.

Work began in 2022 with WELL's primary Field Service Provider on enhancing leading indicators that relate to critical risk controls being in place prior to work commencement. This is progressing well with 10 Critical risk controls strategies implemented and three in the process of roll out. These are monitored monthly to assess the implementation in the field.

Near miss data allows WELL to examine instances where harm could have occurred given slightly different circumstances and review critical controls for effectiveness.

WELL defines a near miss as any unplanned event with a release of energy which could have caused adverse consequences to workers but which did not do so. A hazard observation is defined as being similar to a near miss where the potential for harm exists, but where a release of energy has not occurred.

6.1.3.1 Planning Period Target

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

6.1.4 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 2019 levels, as shown in Figure 6-2. Monitoring continues to help ensure that this trend is continued. There remains a continued focus on compliance with higher risk scenarios such as temporary traffic management requirements, adherence to network standards, and public safety around worksites.

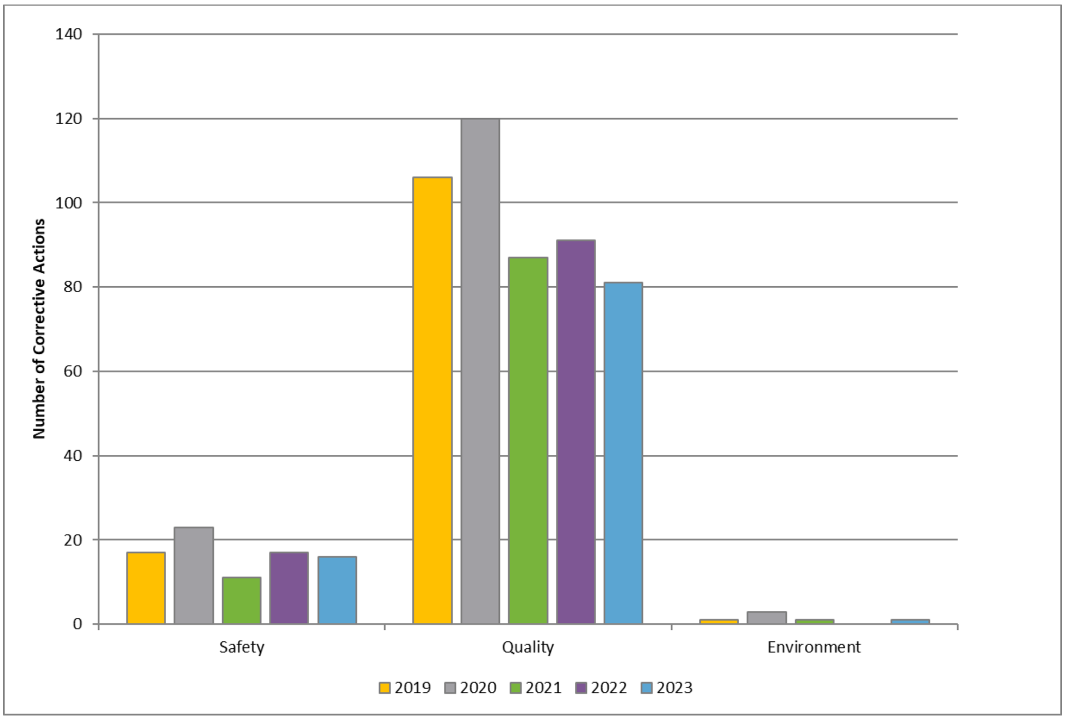

Figure 6-2 Corrective Actions Arising from Assessments 2019-2023

6.1.4.1 Planning Period Target

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

6.1.5 Health and Safety Initiatives

During 2024 focus will be placed on the following areas to further improve safety performance:

- Reinforcement of WELL's safety brand "safer together";
- Increased emphasis on the Te Whare Tapa Whā principles of wellbeing (family, physical, mental, and spiritual) of staff and field workers via focussed programmes and engagements;
- Maintain the timeliness of the close-out of assessments;
- Maintain the application of the risk management framework and expand the risk assessment process with a clear focus on critical risk and control management and principal/contractor communications;
- Maintain critical risk engagement visits to:
  - check that workers have received safety instructions and have adapted work practices or processes as a result;
  - engage with workers over workplace safety and to help ensure WELL's critical risks are being effectively managed; and
  - ensure service provider workers understand all critical risk controls, especially where these interface with WELL risks.

- 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 the development of practical and effective risk controls.

6.2 Reliability Performance

6.2.1 Reliability Measures

Network reliability is measured using two internationally recognised performance indicators, SAIDI[23] and SAIFI.[24] When taken together SAIDI and SAIFI indicate the availability of electricity supply to the average customer connected to the network.

- SAIDI is a measure of the total time, in minutes, that the electricity supply is not available to the average customer connected to the network during the measurement period; and
- SAIFI is a measure of the total number of supply interruptions that the average customer experiences in the measurement period. It is measured as a number of interruptions.[25]

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

- Interruptions caused by the unavailability of supply at a GXP, as a result of automatic or manual load shedding directed by the transmission grid operator,[26] or as a result of some other event external to the WELL network;
- Interruptions lasting less than one minute. In these cases, restoration is usually automatic and the interruption will not be recorded for performance measurement purposes. However, these interruptions are recorded by WELL to understand customer service and for planning and operational purposes; and
- Interruptions resulting from an outage of the low voltage network or a single phase outage of the 11kV distribution network. In practice, such interruptions do not have a material impact on measured system reliability.

The SAIDI and SAIFI targets against WELL's historical performance are shown in Figure 6-3 to Figure 6-6.

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[23] System Average Interruption Duration Index

[24] System Average Interruption Frequency Index

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

[26] 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.

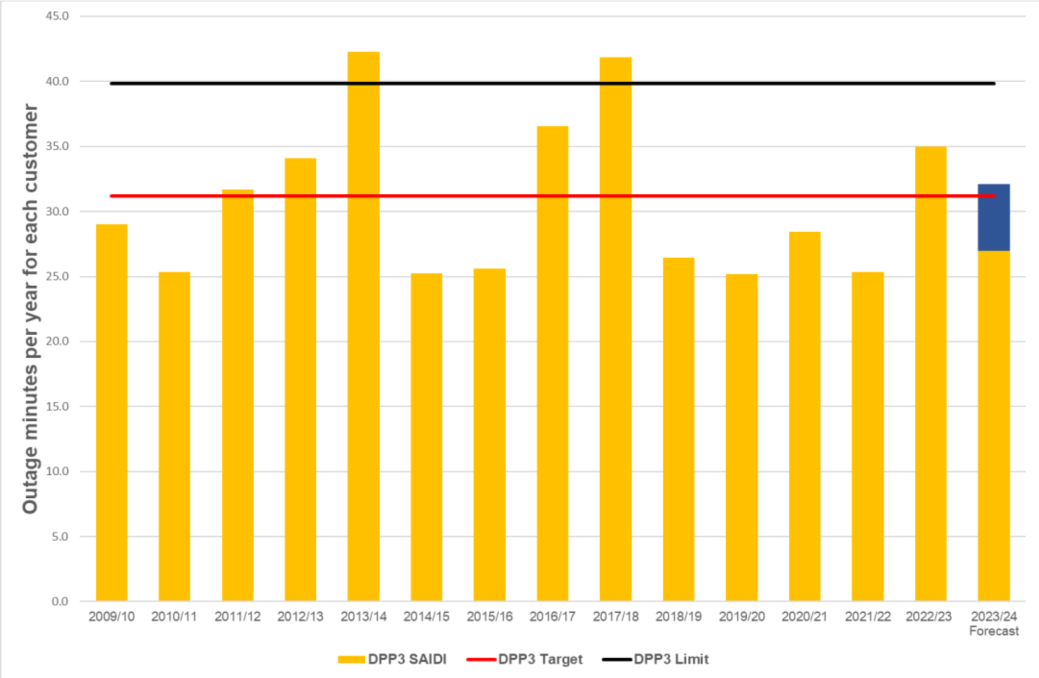


Figure 6-3 WELL Unplanned SAIDI Performance

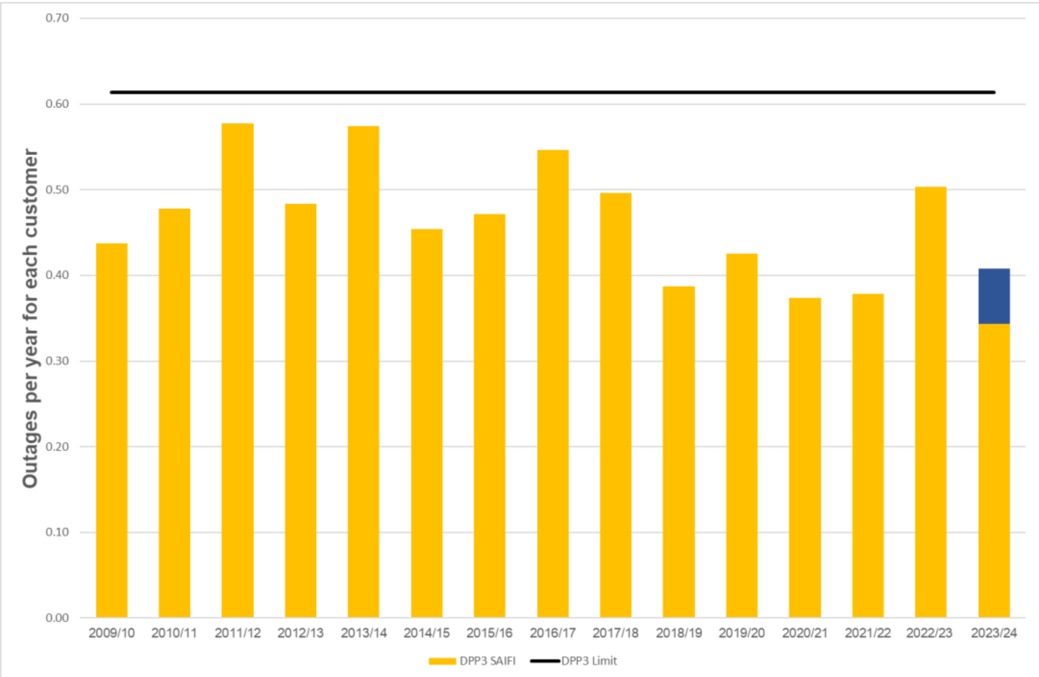


Figure 6-4 WELL Unplanned SAIFI Performance

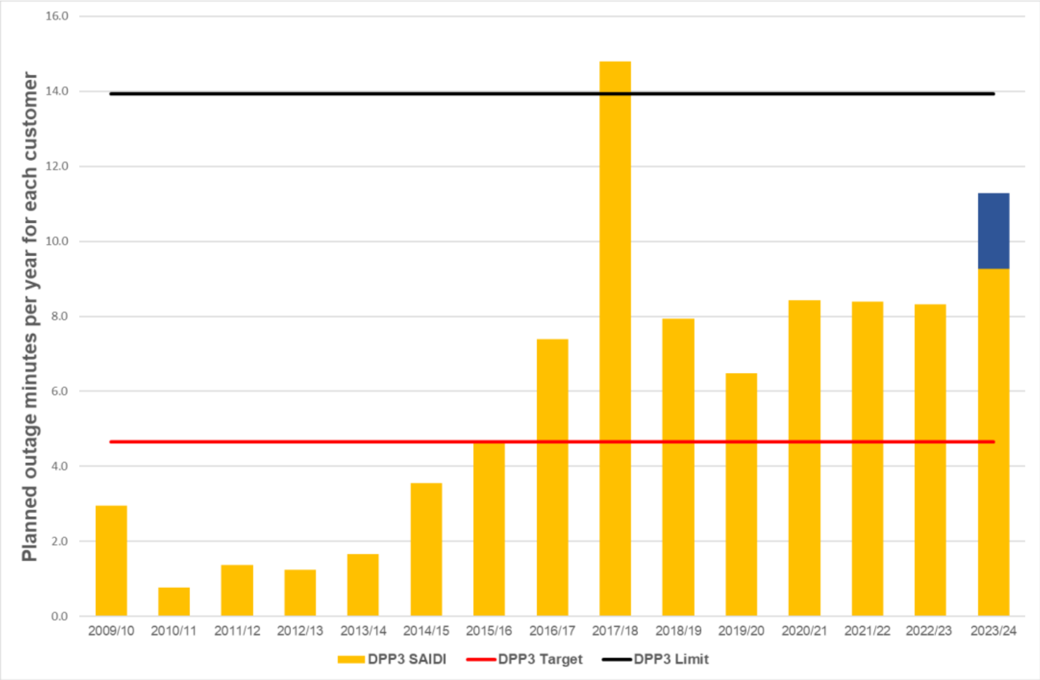


Figure 6-5 WELL Planned SAIDI Performance

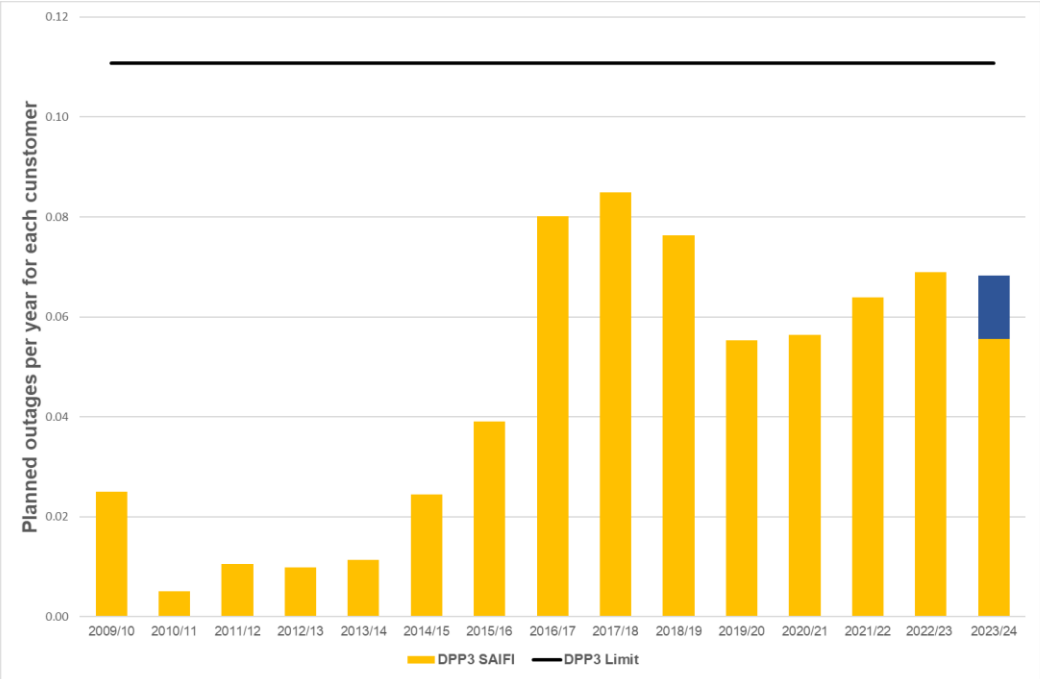


Figure 6-6 WELL Planned SAIFI Performance

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

- Maintain overall network reliability at historically acceptable levels;
- Deliver the cost-quality trade-offs that customers request; and
- Meet regulatory standards on power quality (discussed in Section 9.1).

6.2.2 Process for Measuring Reliability Performance

This section explains how reliability performance is recorded and validated.

6.2.2.1 Outage Data Collection

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

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

The process to record and validate network performance information for planned and unplanned outages is shown in Figure 6-7.

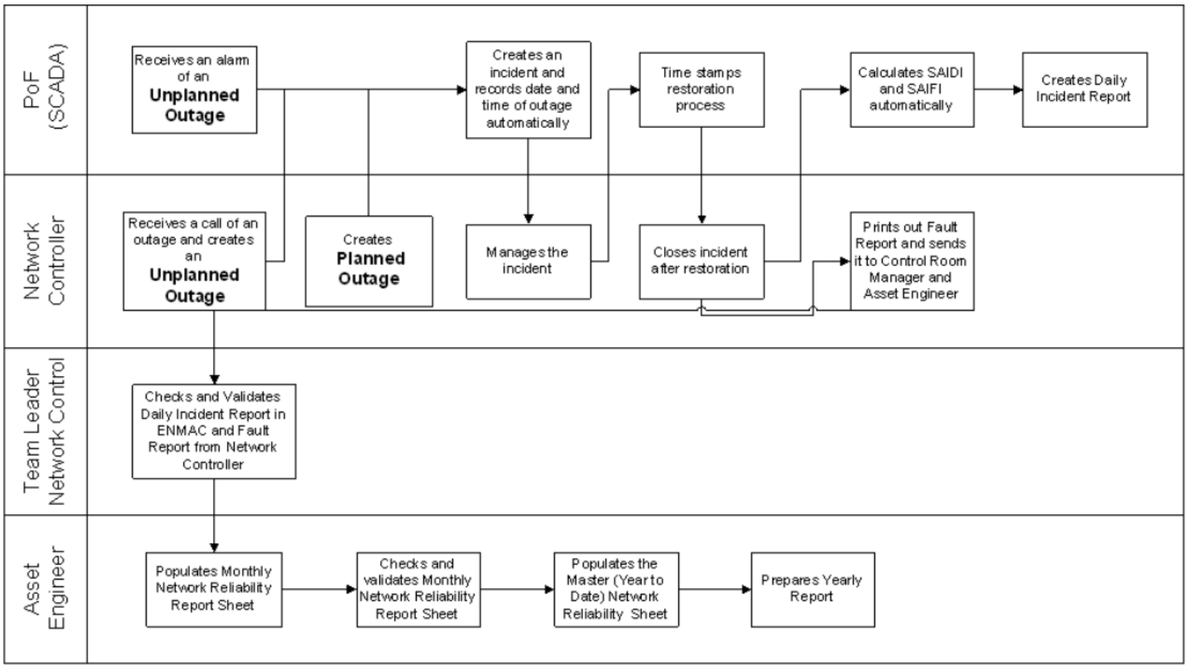


Figure 6-7 WELL Reliability Measurement Process

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

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

6.2.2.2 Data Validation and Review

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

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

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

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

6.2.2.3 Planned outages

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

6.2.3 Industry Comparison

WELL was one of the most reliable EDBs in New Zealand in 2022/23 as shown in Figure 6-8 and Figure 6-9. The data source is the annual Information Disclosures made by EDBs and made publicly available in August 2023. 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).

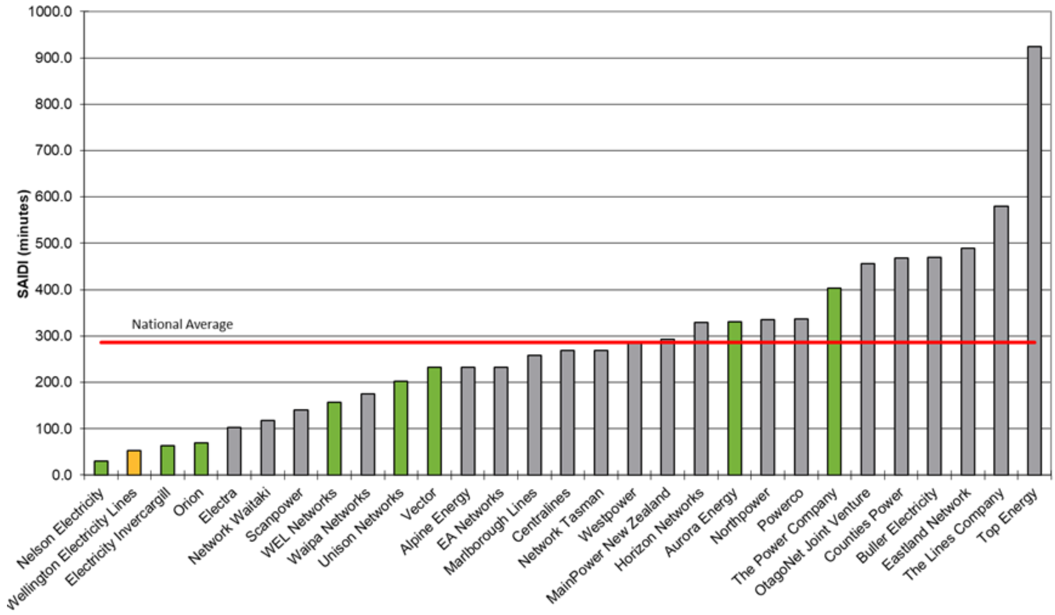


Figure 6-8 National SAIDI by EDB for 2022/23

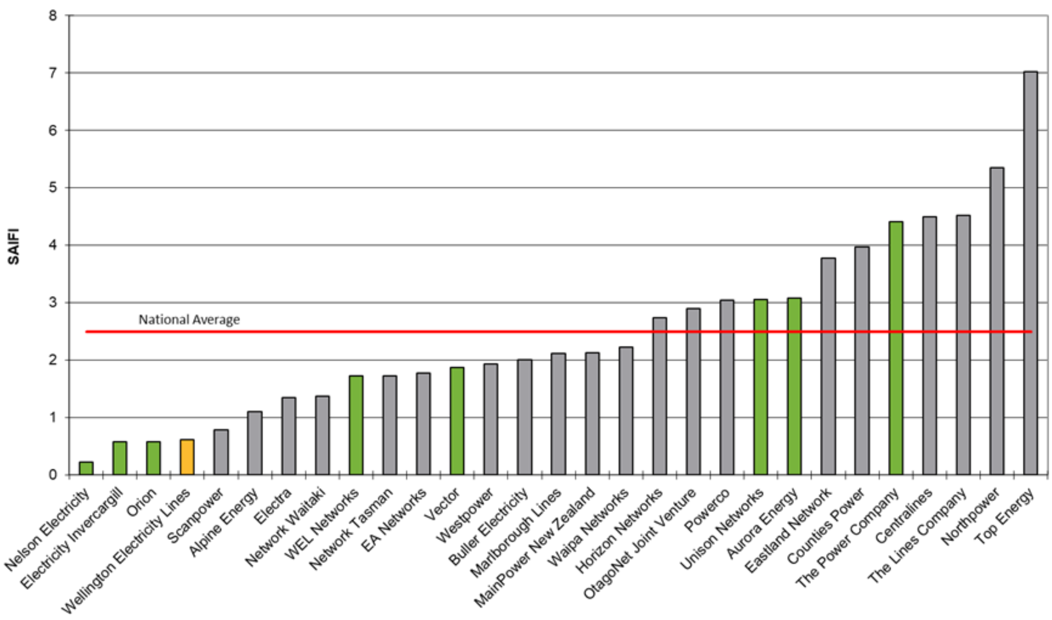


Figure 6-9 National SAIFI by EDB for 2022/23

6.2.4 Reliability Performance in 2023/24

WELL's unplanned network performance for the 2023/24 regulatory year is forecast to be under the annual limit of 39.81 minutes for SAIDI, and under the annual limit of 0.614 for SAIFI.

WELL's SAIDI performance in 2023/24 across a range of fault causes is shown as a waterfall chart in Figure 6-10. The fault causes represented in the chart are:

- Overhead network faults;
- Underground network faults;

- Substation faults;
- Car versus pole faults;
- Other third-party faults;
- Major event days; and
- Other outage types.

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

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

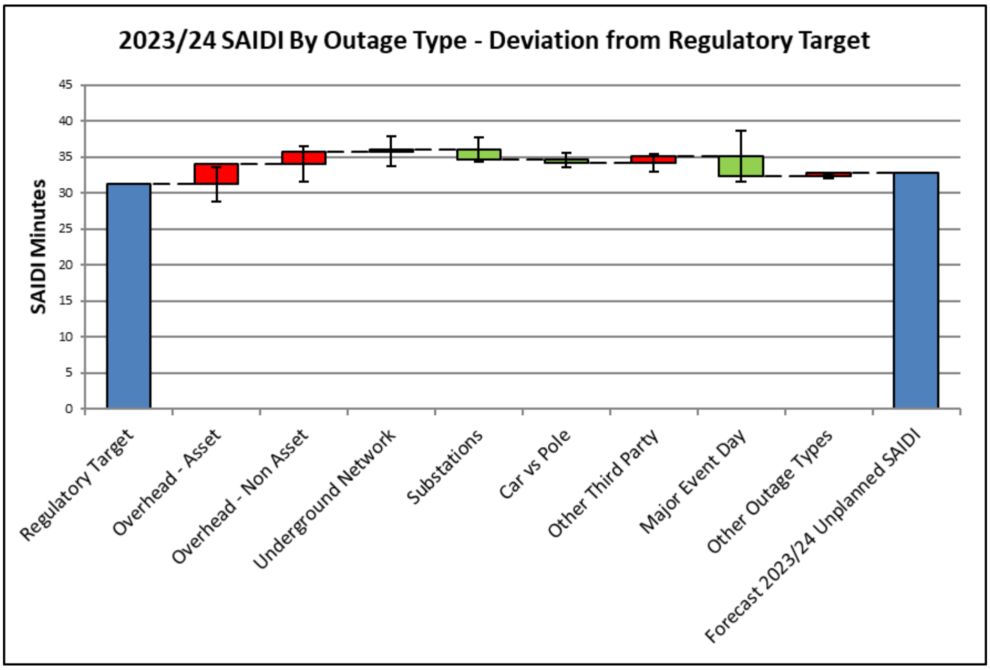


Figure 6-10 Waterfall Chart of 2023/24 SAIDI Performance by Outage Type

The equivalent chart for 2022/23 is shown in Figure 6-11.

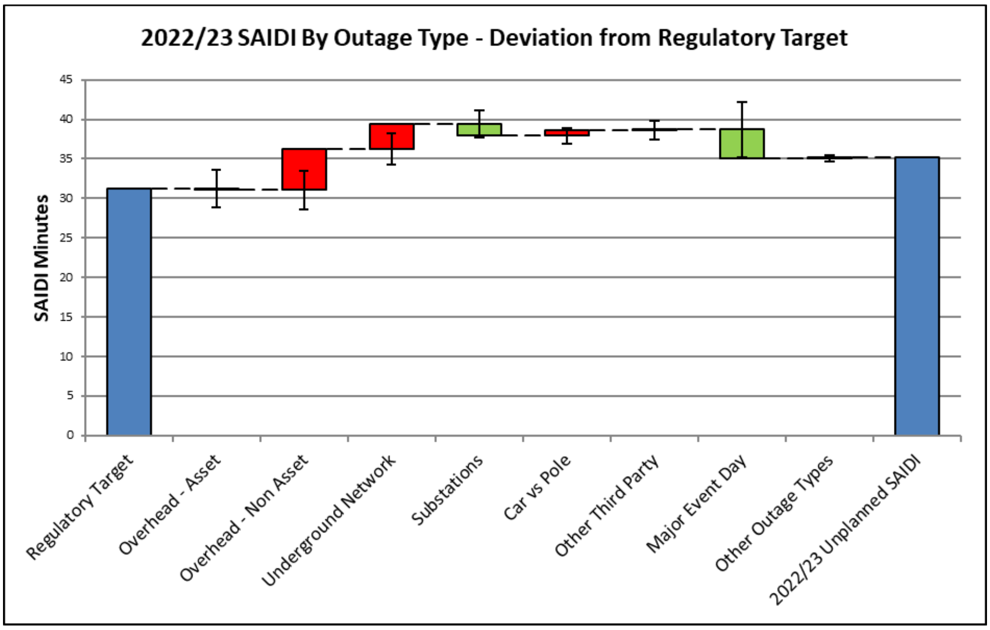


Figure 6-11 Waterfall Chart of 2022/23 SAIDI Performance by Outage Type

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

6.2.5 Reliability Contribution by Network Area

Figure 6-12 and Figure 6-13 show the SAIDI and SAIFI contributions from each network area, representing the availability of electricity supply to the average customer in each region (as opposed to the total number of customers supplied by the network). These charts highlight the difference between the reliability of Wellington city, due to its predominantly underground construction, and the overhead areas supplying the Hutt Valley and Porirua.

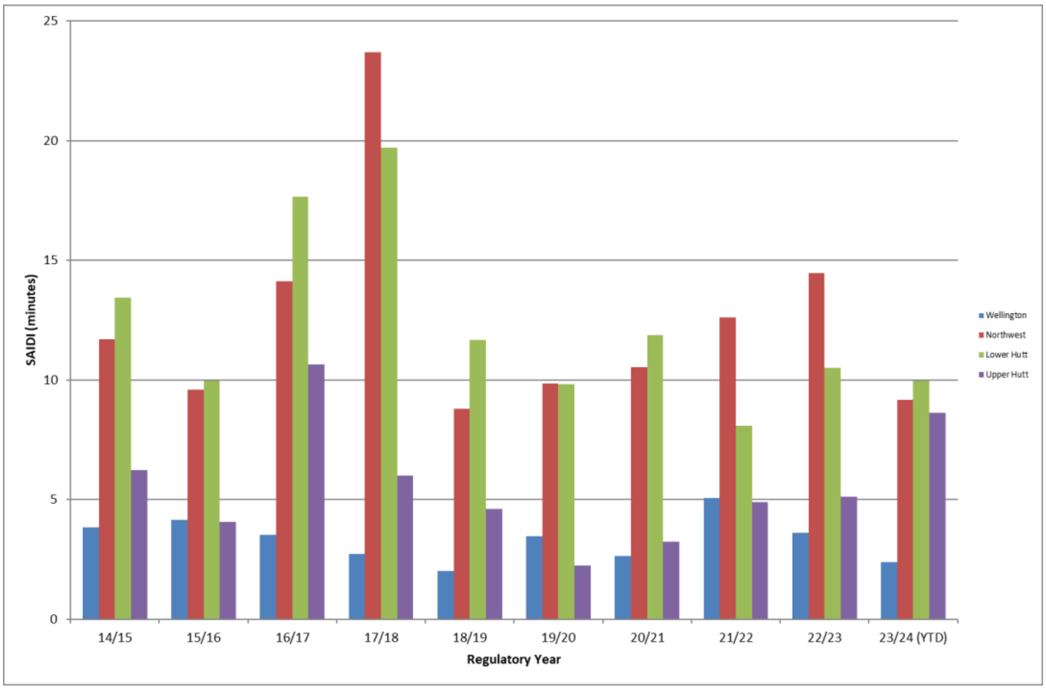


Figure 6-12 Unplanned SAIDI Performance by Network Area

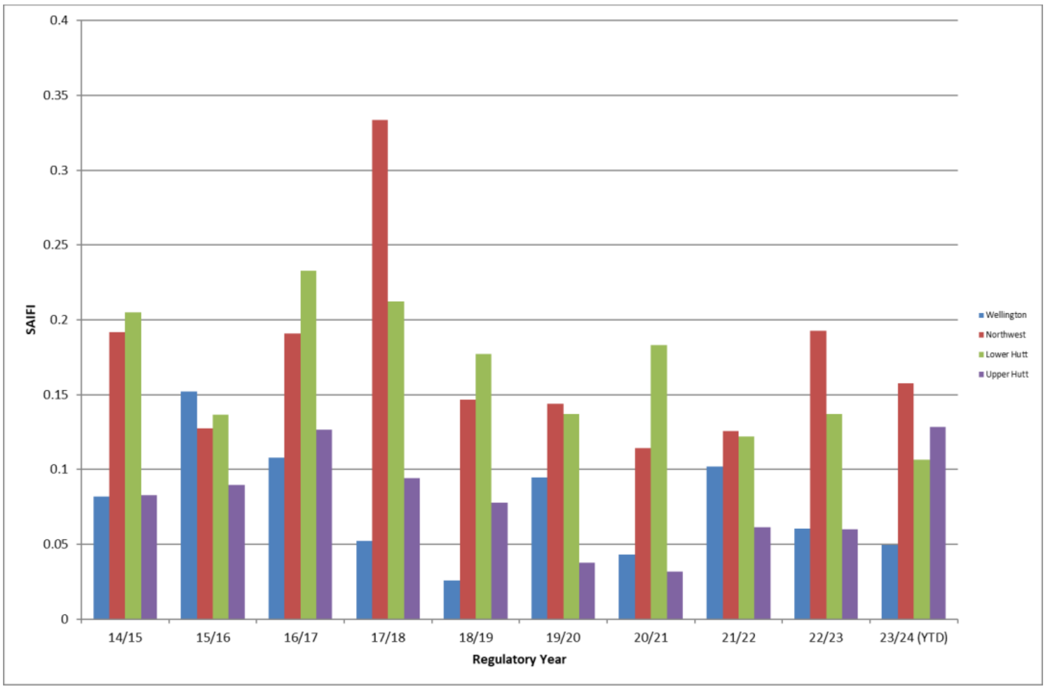


Figure 6-13 Unplanned SAIFI Performance by Network Area

6.3 Asset Efficiency Service Levels

The load factor or utilisation of an asset reflects customer 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.

6.3.1 Planning Period Levels

WELL aims to maintain the high level of utilisation of assets at current levels, and in line with other networks that display similar characteristics. WELL has a very high customer density but below average energy intensity per ICP. Table 6-1 illustrates the level of performance for each measure over the planning period together with key measures of network density.

	Load factor	Zone substation transformer capacity utilisation	Loss ratio	Demand density kW/km	Volume density MWh/km	Connection point density ICP/km	Energy intensity kWh/ICP
Industry Median 2023[27]	58.1%	38.6%	5.0%	34.0	175.8	9.6	14,225
WELL 2023	50.3%	50.4%	3.5%	111.2	473.0	35.9	13,180
Target 2024-2034	>50%	>40%	<5%	-	-	-	-

Table 6-1 WELL Asset Efficiency Levels to 2034

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

[27] Values as per the Pricewaterhouse Coopers (PwC) Electricity Line Business 2023 Information Disclosure Compendium.

6.4 Consolidated Service Level Measures in Retailer Agreements

WELL has service level targets which retailers apply on behalf of their customers. Previously these service levels were included in the agreements with each retailer. WELL has consolidated its service measures and targets that were previously provided in retailer agreements, into this AMP. The Default Distributor Agreement (DDA) refers to these AMP service levels, rather than providing the service levels directly in the agreement itself.

Retailers can find the service levels previously provided in their agreements with WELL in Section 6.4 which details Customer Experience Service Levels. As a minimum, all of the service level measures and targets previously provided in the Use of Network agreement have been included. WELL has consolidated its service levels and standards to:

- Provide clarity and transparency about the levels of quality that WELL will provide. Publishing different service measures in multiple documents could lead to confusion and misunderstanding;
- Ensure service standards are aligned with its regulatory quality obligations and that the standards are at a level that can be delivered within its regulatory allowances;
- Provide WELL with the ability to adjust and refine its service standards to any changes in its price path and regulatory obligations; and
- Allow WELL to transparently link the service standards to the work programmes, operations and funding provided in this AMP.

WELL now provides its service levels in the AMP, rather than in agreements with retailers, because legislation protecting customers and the regulatory framework for distribution businesses has evolved since the current agreements with retailers were developed. The Consumer Guarantees Act, the Utility Disputes framework and price/quality regulation under Part 4 of the Commerce Act provide better consumer protections than those provided in previous retailer agreements (i.e. the Use of Network Agreements). Specifically:

- The Consumer Guarantees Act provides sufficient (and arguably more appropriate) remedies for customers than Service Guarantee Payments included in retailer agreements, which are arbitrary and can be administratively burdensome on all parties. WELL does not believe the existing service guarantee scheme or credit payments provided an effective incentive framework. Both have rarely been needed on the Wellington network. By comparison, WELL spends considerably more in providing individual reparations as part of its in-house complaints process.
- The Commerce Commission regulates service quality and price under Part 4 of the Commerce Act 1986. WELL is penalised for not meeting its quality targets with the penalties passed back to customers as a price decrease. WELL believes that any penalties or payments relating to quality must relate, or at least be consistent, with the price path. This allows a distributor to be adequately funded to provide the level of service a customer is willing to pay for, i.e. price and quality are balanced.
- WELL has an internal disputes resolution process that resolves the majority of customer complaints. WELL also participates in the Utilities Disputes process. The Utilities Disputes process provides a backstop for issues that are unable to be resolved internally and is rarely required.

6.5 Customer Experience Service Levels

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

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

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

In 2023, WELL engaged in a number of customer experience and community engagement initiatives, with some examples being:

- **Connections & Self-Service:** During 2023 a change to the pricing model for small to medium network extensions was implemented in response to feedback received from customers. Customers were provided with a new two-tier pricing option which reduced the variability of the pricing which they would have experienced previously. A small number of functionality and navigation enhancements were deployed to the self-service platform at the same time The changes were intended to enhance the experience for customers and remove a potential hurdle for a significant number of customers seeking a new connection to the network. The publication of planned outage details has been trialled on the WELL website throughout 2022 and 2023.

- **Community Engagement:** WELL met with members of the Pauatahanui and Wainuiomata (Moores Valley Road residents) Communities during 2023. For the Pauatahanui community the meeting was a follow-up session to provide residents with an update on the project work conducted since the previous meeting. The work's positive impact on power reliability within the area was presented as was a timeline for remaining work. The Moores Valley Road residents were engaged in advance of a project to re-build and replace a significant part of the power line and its assets which supply the area.

  In addition to a focus on each community's recent network reliability performance and how they can contribute, presentations covered the potential impacts of the government's plans to meet decarbonisation goals and how WELL plan to respond to those impacts.

  Staff continued to meet in person with a number of customers who had lodged complaints, to better understand their experience and to help identify the root cause of their complaints. This is an important component of WELL's Root Cause Programme, described below.

WELL hosted stands at Wellington's Home & Living and Home & Garden Shows. For the former, WELL's stand was focused on showcasing how customers can save money on their power bills. The theme was amended for the latter show to provide customers with an insight into the potential impacts of the government's decarbonisation targets on our electricity network. They also had an opportunity to 'have a say' in relation to what is most important to them – choosing between Decarbonisation, Resilience, Reliability and whether they would be prepared to have someone manage part of their electricity consumption.

- **Planned (and Unplanned) Outage Publication:** Planned outages are currently sent by WELL to retailers, who in turn publish those outages to their customers. During 2023 WELL deployed a system to semi-automate the Network Access Request (NAR) process for its contractors. NARs commonly involve the need for outages (Planned Outages) to the WELL network so that its contactors can safely conduct their work. Deployment of the NAR system will in turn enable automation of the publication of planned outages on the WELL website during 2024, providing greater visibility of upcoming outages for customers.

- **Community Education:** Throughout 2023, in addition to the Community Engagement meetings and Trade Show stands the suite of animated videos available through the SmarterPower portal was roadedn to include a number of new topics. The site focuses on providing simple explanations and tools to explain potentially complex industry and network topics.

  The Staysafe area of the WELL website. Staysafe was enhanced to introduce a new animated video, focused on a electricity safety for children. A pilot presentation of the video was conducted at a local childrens' school to get feedback on the video and the Staysafe electricity programme. Feedback from children and teachers was mainly positive.

- **Root Cause Programme:** The Root Cause Programme targets people, process, and system gaps which may have led to customers expressing dissatisfaction with the service they have received. Staff of both WELL and its contractors meet to review complaints raised and work together to develop solutions to address those complaint causes. The programme yielded a 9% reduction in customer complaints received during 2022, on top of a 30% decrease in customer complaints during 2021.

- **Major Customer Engagement Programme:** In 2023 a series of meetings and interviews were conducted with organisations who had significant electricity consumption needs, now and potentially in the future. Some of the organisations were large users of natural gas. The government's decarbonisation goals forecast that the use of natural gas will be transitioned to electricity over the next 30 years which in turn will drive significant electricity consumption growth in our network. The purpose of these sessions was to gain an understanding of their needs and to provide an insight into how they could best work with us to meet those needs.

In 2024, WELL will be delivering:

- **Self-service Improvement:** Continued development of the web-based self-service platform to further improve its functionality and to deliver an improved customer experience. Changes will be made to help streamline the experience for medium to large new connection and upgrade requests.

- **Service Improvement:** WELL continues to analyse and target for improvement the root causes of complaints received from customers and/or their retailers. As part of that programme, WELL staff members will visit a number of customers who have reported poor service throughout the year, in order to better understand their experiences.

- **Community Engagement:** WELL plans to continue engaging with communities most impacted by outages as part of the 'Worst Performing Feeder' programme. The programme aims to update customers on network activities in their area and inform customers of actions they can take to help improve their electricity supply, such as vegetation management. WELL also regularly engages with city councils in the Wellington region with regard to the Tree Regulations and the issuing of trim and cut notices. This is a practice that will be continued as it helps support WELL to maintain reliability levels for customers.

  WELL will pilot a customer education programme to inform customers of what actions they can take to reduce their electricity costs and mitigate the risks of energy supply constraints by shifting their electricity consumption to times of the day when the national and local networks are less busy.

  WELL will maintain a presence at trade shows to help engage with the wider community on key industry and network topics.

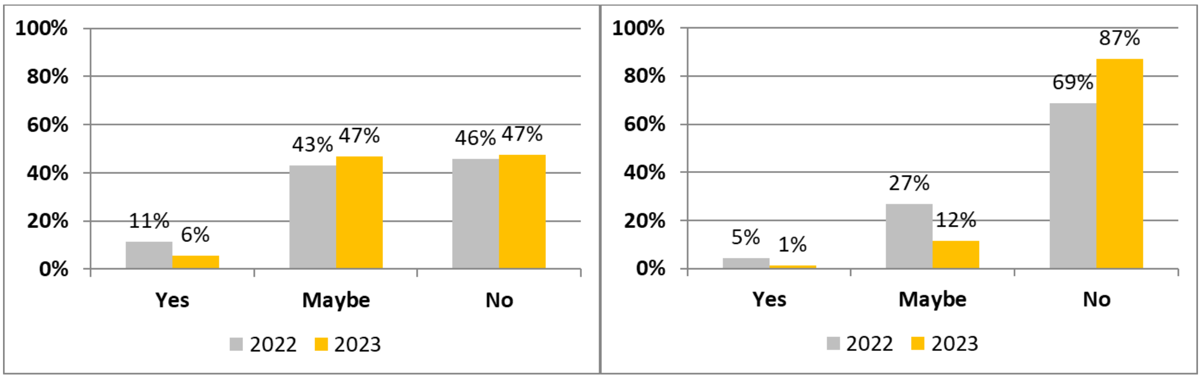
  In addition, as mentioned above a number of customers impacted by perceived poor service will be visited to better understand their experiences.

- **Planned (and Unplanned) Outage Publication:** As described above, a system was progressively deployed throughout 2023 to enable the semi-automation of NARs. The final phase of the project will enable the automated publication of planned outages. At the same time that this change is made, we are also enhancing the website to publish recent as well as current unplanned outages. This is in response to customer requests for greater visibility of all outages on our website.

- **Community Education:** The Government's proposals to help New Zealand reduce its carbon emission levels are likely to result in increased demand for electricity and significantly impact the network. WELL will continue to engage with and educate customers on the impacts of the government's decarbonisation targets on our network, what we are planning to respond to those changes and what customers can do to influence their levels of electricity reliability, resilience and costs.

6.5.1 Customer Surveys

WELL conducts a monthly customer survey to understand customer perceptions across a range of factors and includes questions which seek to understand whether customers perceive that the price-quality trade-off they receive is appropriately balanced. The monthly survey group ("Monthly Outage Sample") consists of customers who have recently experienced an outage, on the basis that they are more engaged on the issue and are better positioned to provide a considered response to queries. The results of that survey are compared in Figure 6-14 for two of the key price-quality trade-off questions.



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

Figure 6-14 Sample of 2023 Customer Survey Results

For Question 1, the percentage of people willing to pay a bit more for power in return for fewer power cuts has reduced and remains low, with the remainder of customers evenly split between unsure or unwilling to pay more for fewer power cuts.

The results for Question 3 suggest that customers are unwilling to experience a drop in the reliability of their power supply in response to a reduction in price.

A copy of the same set of questions is available on the Consultation page on the Wellington Electricity website.[28] At this point in time, the sample set of data collected from customers responding via the website is too small to provide a material comparison.

6.5.2 Power Restoration Service Levels

WELL has two power restoration service levels: Urban and Rural. These service levels reflect previous feedback from customers and are agreed upon between WELL and all retailers. An Urban Fault is defined as a network fault that results in a complete loss of supply to one or more points of connection within an urban area. A Rural Fault is any fault resulting in a complete loss of supply to one or more points of connection in a rural area. The geographical regions categorised by the urban and rural power restoration areas are shown in Figure 6-15.

[28] https://www.welectricity.co.nz/about-us/consultation/

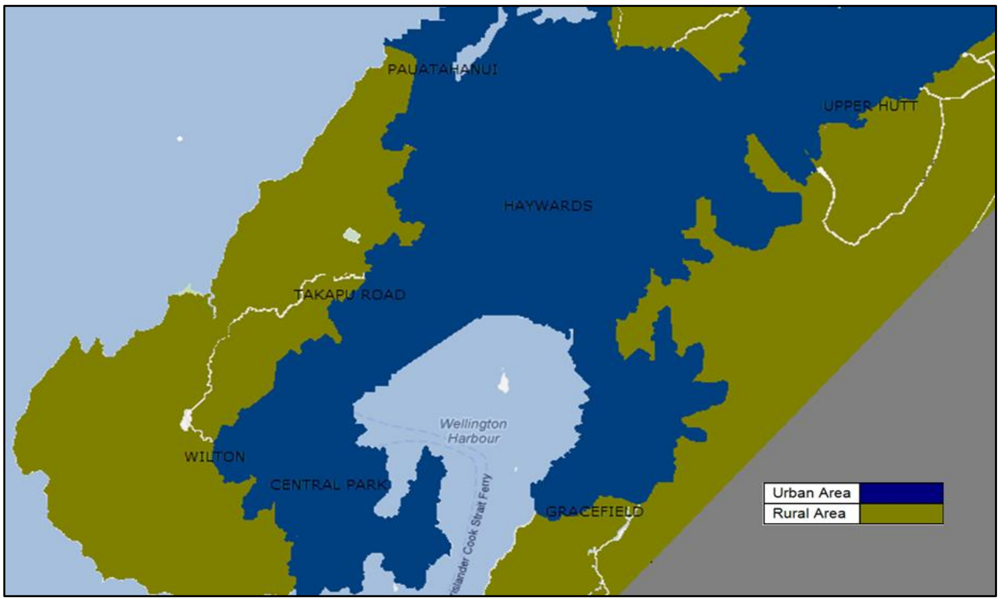


Figure 6-15 Geographical Map of Power Restoration Areas

6.5.2.1 Planning Period Targets

The targets for the power restoration service levels remain consistent over the planning period 2023-2033, as set out in Table 6-2.

	Urban	Rural
Maximum time to restore power	3 hours	6 hours

Table 6-2 Standard Power Restoration Service Level Targets 2023-2033

6.5.3 Notification of Faults and Outages

In addition to reliability and appropriate prices, customers increasingly expect accurate, timely information on their service and its status. Most customers accept occasional power cuts if they are kept informed of restoration times after a fault. Ensuring a reliable, effective information flow is therefore a priority for achieving good customer service. In support of this priority, WELL sets and tracks performance targets for its Contact Centre. WELL is also developing plans to ensure 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.

WELL publishes information about unplanned outages on its website and mobile app, however, the primary path of information about outages is from WELL to retailers, who will then inform their customers. WELL's service levels for the notification of outages focus on the time taken to inform retailers. These notification service levels are set out in Table 6-3 (Unplanned outages) and Table 6-4 (Planned outages).

Outage Type	Notification Action	Notification Service Level
Area Network Fault	Provide retailer(s), to the extent reasonably known at the time: • A description of the reason for the interruption; • The area affected; and • An expected time for restoration.	Within 5 minutes of the fault being notified to WELL
Service Interruption	Provide retailer(s) with status updates	Within 5 minutes of new information becoming available; and At intervals no greater than 30 minutes
Expected (advised) restoration time likely to be exceeded	Notify retailer(s)	Not less than 10 minutes before the existing restoration time elapses
Partial or full restoration of supply	Notify retailer(s)	Within 5 minutes of the partial or full restoration of supply

Table 6-3 Unplanned Outage Notification Service Levels

Outage Type	Notification Action	Notification Service Level
Upcoming planned outage	Notify retailer(s)	10 working days
Semi-planned outage for emergency repairs	Inform retailer(s)	As soon as is reasonably practicable

Table 6-4 Planned Outage Notification Service Levels

6.5.4 Notification of New Connections

After receiving an application for a new connection, WELL passes connection details on to the retailer so the retailer can liaise with the end customer. Table 6-5 provides WELL's notification timeframes for new connections.

New Connection	Notification to Retailer
Receipt of application	1 working day
Connection approval if no site visit is required	2 working days
Where the application requires network expansion before approval	2 working days
Where connection approval requires conditions to be met prior, a site visit, and/or network expansion	1 working day

Table 6-5 New Connection Notification Timeframes

6.5.5 Connection, Disconnection, Capacity Change Timeframes

Table 6-6 provides the timeframes for new connections, disconnections and capacity changes.

Activity	Requirements	Time to Action
Livening a new connection	Dependent on: • All necessary equipment in place; • Network upgrades or extensions not required; and • All other necessary requirements met.	4 working days
Temporary disconnections	If the retailer provides authority to do so. If the retailer requests more than 20 disconnections (whether Vacant Site, Permanent or Temporary) or re-connections in any one day WELL may not be able to meet this service level.	1 working day
Notification of capacity change request	WELL will advise the retailer within the same timeframe whether or not the request is accepted and the requirements in respect of the Point of Connection that must occur prior to the capacity change being made.	1 working day
Capacity change where only a fuse change is required	If the capacity change requested is likely to interrupt the supply to other end customers, the capacity change may be delayed.	1 working day
Vacant Site Disconnection or a Permanent Disconnection	Provided that: • Access is available; and • There is an accessible isolating device (fuse) which isolates only the requested Point of Connection If the retailer requests more than 20 disconnections (whether Vacant Site, Permanent or Temporary) or re-connections in any one day WELL may not be able to meet this service level.	2 working day
Reconnections after a Vacant Site Disconnection (field-energise an existing Point of Connection)	Service level only applies where there is an accessible isolating device (fuse) which isolates only the requested Point of Connection.	1 working day

Table 6-6 New Connection, Disconnection and Capacity Change Timeframes

6.5.6 Supply Quality Investigations

WELL monitors voltage quality on its low voltage network through customer reports of abnormal voltage. This is because WELL does not have ready access to smart meter voltage data that would allow it to undertake a more systematic review of voltages across its network.

When a retailer notifies WELL about a supply quality problem on the network, WELL will investigate the problem and respond to the retailer detailing the nature of the problem. The investigation of voltage quality problems is becoming significantly more complex due to the increasing prevalence of DER and the potential for two-way power flows. Table 6-7 sets out WELL's response timeframes for supply quality investigations.

Supply Quality Investigations	Time to Action
Investigate problem and respond to the retailer detailing the nature of the problem	7 working days
Where investigation cannot be completed within 7 working days, provide an estimate of the additional time needed	Within 7 working days

Table 6-7 Supply Quality Investigation Timeframes

The increased penetration of DER in the network is increasing the number of queries relating to the supply voltage. In many cases, investigation shows that the voltage at the point of supply is within the allowed range defined in the Electricity (Safety) Regulations 2010, and the cause is voltage drop within the customer's installation. An EDB's responsibility for voltage is to maintain 230V±6% at the point of supply. If this requirement is being met, then the EDB is not responsible for the voltage seen by appliances located within the installation. Public education is required to ensure that it is understood that voltage measured at the inverter (or some other smart appliance located within the installation) is not necessarily indicative of the supply voltage being outside of its acceptable range.

Where a voltage quality non-compliance is confirmed to exist in the network, WELL responds. These responses could include undertaking a distribution transformer tap setting change, altering network open points, or a CAPEX response such as installing larger distribution cables or an additional transformer. The challenge with these responses is the timeframe needed to undertake a thorough analysis, develop the most cost effective solution, and implement the solution. This is particularly the case for responses that require planned outages and equipment procurement, as these are affected by supply chain lead times and outage notification requirements. In addition, it is essential to ensure that the identified voltage problem is being resolved in a manner that does not cause additional problems for other customers, for example by ensuring that lowering a tap setting in response to a report of high voltage during summer will not subsequently result in reports of low voltage during winter.

6.5.7 Customer Complaints

WELL receives customer complaints and enquires via its contact centre, and has adopted the Utilities Disputes Code of Practice for managing complaints. All 'Times to Action' (timeframes in which WELL responds to complaints and enquiries) comply with the Utilities Disputes rules and protocols. These are set out in Table 6-8.

Customer Complaints and Enquiries	Time to Action
Acknowledge receipt of a complaint or enquiry	2 working days
Respond to an enquiry; or Advise that more time is needed and provide a reason for the time extension	8 working days
Resolve complaint; or Advise that more time is needed and provide a reason for the time extension	10 working days

Table 6-8 Complaint and Enquiry Response Timeframes

6.5.8 Contact Centre Service Levels to Customers

WELL measures the service level performance of its Contact Centre through a set of key performance indicators (KPIs). 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.

6.5.8.1 Contact Centre Targets

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

1. Grade of Service (GOS) (A1) - This measures the percentage of calls which are answered within a set threshold of 30 seconds. The target is for 85% of calls to be answered within this timeframe.

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. Call Quality (C1): 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 to identify potential opportunities for call quality improvement, with a target quality score of 85% or better.

6.5.8.2 Planning Period Targets

The Contact Centre service level targets are to provide consistent performance over the planning period 2023-2033. These are shown in Table 6-9.

SL	Service Element	Measure	Target	2023 Performance
A1	Grade of Service	Average service level across all categories	>=85%	87.89%
A2	Call response	Average wait time across all categories	<20 seconds	17.48 seconds
A3	Missed calls	Total missed/abandoned calls across all categories	<4%	2.61%
C1	Call Quality	Agent performance against 16 key quality criteria for a random selection of calls	>=85%	90.13%

Table 6-9 Contact Centre Service Level Targets 2023-2033

Section 7

Reliability Performance

7 Reliability Performance

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

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

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

7.1 Reliability Performance Limits and Targets

The regulatory regime that applies to WELL sets reliability limits for each year. The DPP3 price-quality regime in place for 2021/22 to 2024/25 set limits for outages that are based on historical performance during a reference period of 1 April 2009 to 31 March 2019. Unplanned outage limits are set at two standard deviations above the reference period average, while planned outage limits are set at 300% of the reference period average. The regulatory limits for WELL are presented in Table 7-1.

Regulatory Year	2021/22-2024/25
Annual Unplanned SAIDI Limit	39.81
Annual Unplanned SAIFI Limit	0.6135
Period Planned SAIDI Limit	55.76
Period Planned SAIFI Limit	0.4429
Extreme Event Customer Minutes Limit	6 million

Table 7-1 WELL Regulatory Reliability Limits

Figure 7-1 shows the last 13 years of actual unplanned SAIDI renormalised using the DPP3 methodology, against the DPP3 unplanned SAIDI target and limit.

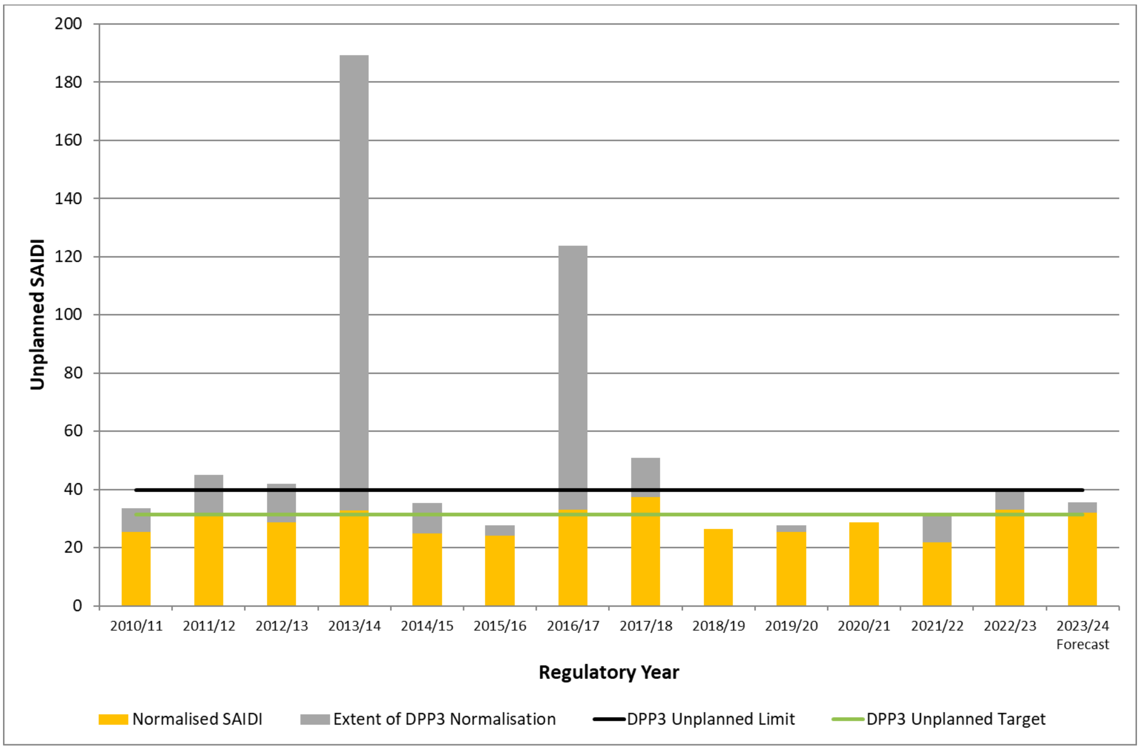


Figure 7-1 DPP3 Normalisation Applied to Historical Unplanned SAIDI Performance

WELL's targets for SAIDI and SAIFI are shown in Table 7-2. These targets assume that SAIDI and SAIFI beyond 2025 will be calculated using the same methodology as the DPP3 determination, including the mechanism for normalising Major Event Days.

Regulatory Year	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Unplanned SAIDI target	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20	31.20
Unplanned SAIFI target	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480	0.480
Planned SAIDI target	12.23	17.05	17.02	16.43	15.90	15.17	15.01	14.99	15.03	15.09
Planned SAIFI target	0.068	0.095	0.095	0.091	0.088	0.084	0.083	0.083	0.084	0.084

Table 7-2 Network Reliability Performance Targets

WELL will need to increase its planned outage targets over the period due to a large increase in its work programme caused by decarbonisation load growth. While most of the increase in expenditure will be related to subtransmission and zone substation reinforcement projects that can be completed without any customer outages, there will also be a significant increase in 11 kV reinforcement, which will increase planned outage indices.

The planned outage forecast is based on the following assumptions:

- Approximately 67% of recent Planned SAIDI has been due to capital works, with the balance being due to maintenance.

- Maintenance SAIDI will be constant into the future, i.e. there will be no significant change in the maintenance requirements for existing assets, or changes to work practices (e.g. new rules around live work).
- Planned SAIDI due to capital work is proportional to the sum of Growth, Renewal, Relocation, and Quality of Supply expenditure, excluding expenditure on Subtransmission, Zone Substation, and Distribution Cable assets.
- Planned outage efficiency (SAIDI per CAPEX dollar) will remain constant throughout the period.
- Planned SAIFI is proportional to Planned SAIDI, i.e. Planned CAIDI will remain constant through the period due to the nature and duration of outages not changing.

7.1.1 Extreme Event Compliance Standard

DPP3 introduced an Extreme Event compliance standard. The purpose of this standard is to identify events with an extreme impact on customers that would otherwise not be captured by the other quality measures due to the effect of Major Event Day (MED) normalisation. Wellington Electricity's Extreme Event standard is set at 6,000,000 customer minutes, which currently equates to 34.6 SAIDI minutes. The standard excludes outages caused by external factors such as storms and third-party interference.

WELL has reviewed the areas of its network at risk of experiencing an Extreme Event, and these are summarised in Table 7-3.

Extreme Event	Outage Duration to Exceed Standard	Solutions to Reduce Consequences
33kV Cable Fire at Central Park GXP	2 hours	• Cables within the switchroom have intumescent coatings. • The planned expansion of the site to increase redundancy (see Section 12.5.1).
Loss of Wainuiomata Zone Substation	17 hours	• Fire suppression was installed in the Wainuiomata switchroom in 2021. • Mobile substation and generation connection points.
Loss of Karori Zone Substation	25 hours	• Pre-establish generation connection points.

Table 7-3 Top Three WELL Extreme Event Risks

7.2 Reliability Strategies

From a reliability management perspective, WELL defines three types of outages: unplanned, planned and High Impact Low Probability (HILP). The strategies relating to these outage types are provided in Table 7-4.

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

Table 7-4 Strategies Relating to Different Types of Outages

7.2.1 Unplanned Outages

Asset Fleet Strategies

Asset fleet strategies focus on the management of a specific asset fleet and are discussed in Section 8. The fleet strategies are a predictive tool used to develop the actions needed to achieve targeted future reliability levels. A fleet strategy includes a risk assessment of an asset class which considers population characteristics and asset health and criticality indicators. The output is a list of asset management actions for the fleet which are needed to achieve expected asset performance and reliability. The fleet strategies drive asset condition and asset reliability – key factors influencing the current and future likelihood of unplanned outages and ultimately the customer service provided.

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

The fleet strategies include forecasting which is used to estimate future population replacement rates and is a key input into forecast fleet expenditure. These forecasting methods are described in Section 8.2.

Secondary Asset Fleet Strategy

The secondary asset fleet strategy provides the protection and fault indication requirements to effectively manage network security to limit the consequence of unplanned outages. This strategy is discussed in Section 8.5.9.

Network Development Strategies

Network development strategies and plans ensure that the network remains at the targeted security levels, which helps maintain the integrity of the network when outages occur. These strategies are discussed in Section 9.

7.2.2 HILP Outages

Resilience Strategy

A specific portfolio strategy is the Resiliency Strategy discussed in Section 12. The Resiliency Strategy outlines the investment needed to mitigate HILP events. Following the 2016 Kaikoura earthquake, there was a heightened awareness by stakeholders of the risk of major earthquakes in the region, and this has led to a major investment in this area. Although this is not captured by the quality standards, WELL's improved readiness for a major event is valued by its stakeholders and customers.

7.2.3 Planned Outages

Planned Outage Strategy

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

7.3 Reliability Reporting

Figure 7-2 shows WELL's reporting structure for reliability performance management and includes the associated regular meetings to support each level of governance and management, and the key reports provided.

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

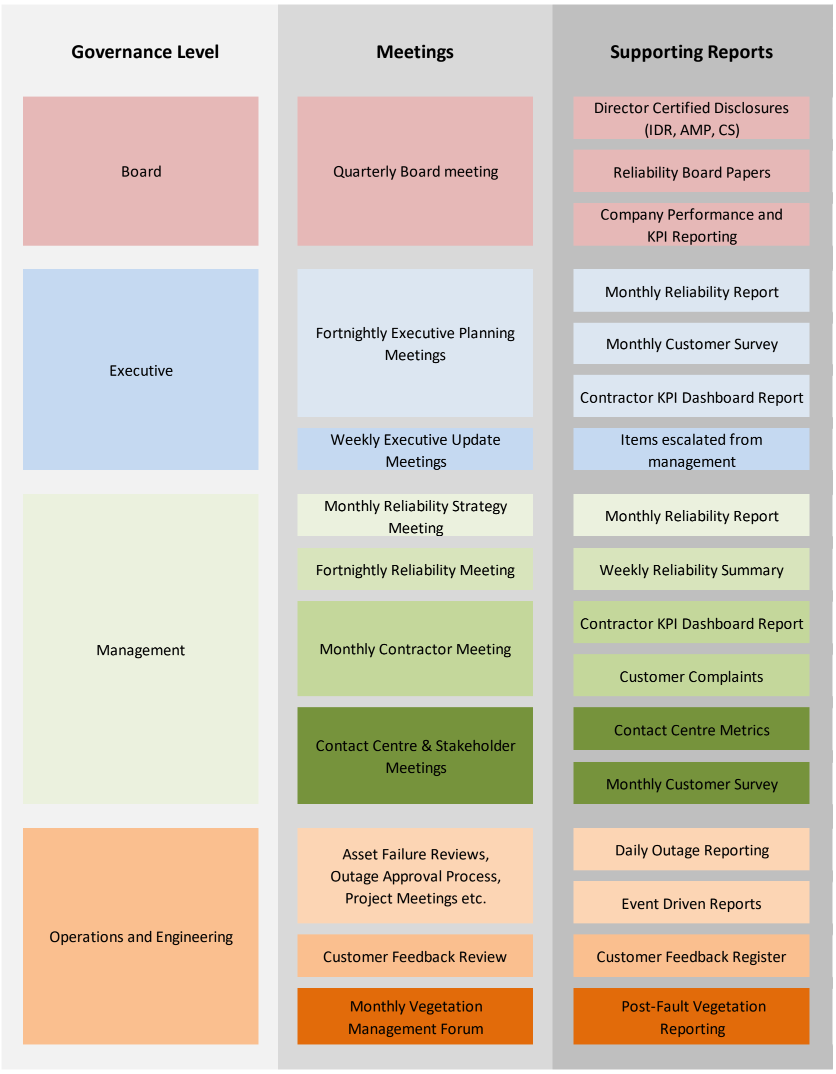


Figure 7-2 WELL's Reliability Reporting Structure

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

7.3.1 Forecasting SAIDI by Fault Type

The forecast by SAIDI type is based on the historic monthly distribution of SAIDI due to each cause. This forecasting method takes year-to-date SAIDI by outage cause and scales it by the proportion of annual SAIDI due to that cause that has historically occurred each month. A waterfall chart is used to display this data, with an example given in Figure 7-3.

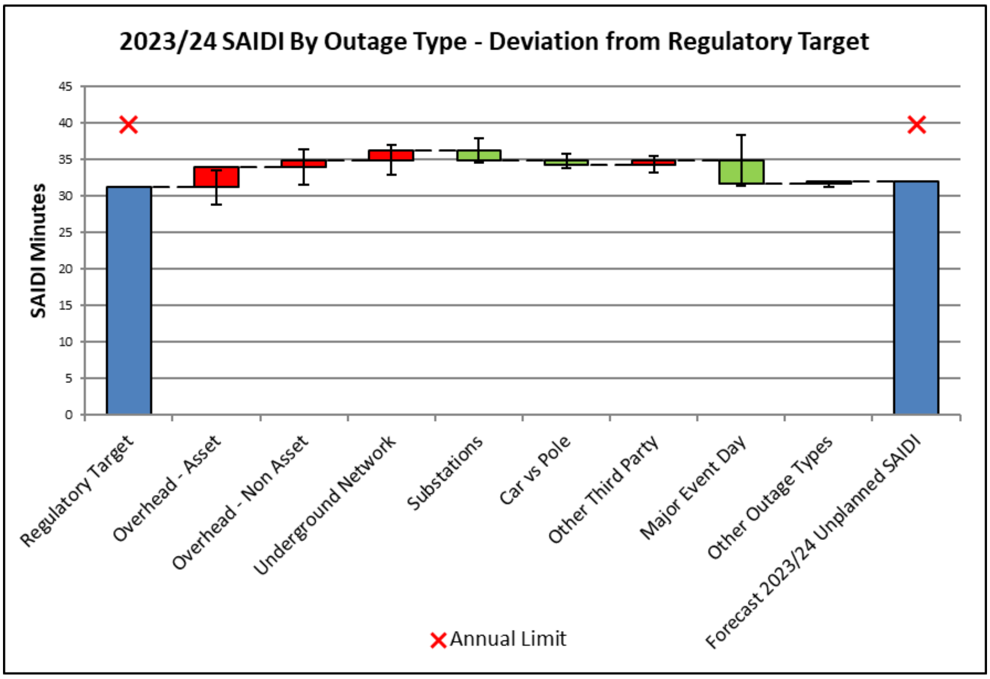


Figure 7-3 Waterfall Chart of 2023/24 SAIDI Performance by Outage Type

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

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

7.3.2 Reliability Trend Analysis

Detailed outage trend analysis is critical for providing confidence that the performance of the assets is not deteriorating. WELL's monthly reliability report to the Executive includes an analysis of trends in monthly SAIDI by outage type.

If any material trends are evident in the monthly SAIDI, these outage types are analysed in greater detail, breaking SAIDI down into its components of frequency of outages, duration of outages, and number of customers being affected, examining the trends in each to determine the underlying driver of the SAIDI trend. The trends in these components are then reviewed at the Reliability Strategy Meeting, to consider whether additional controls may be required to reverse the trend.

An example of this trend reporting is given in Figure 7-4.

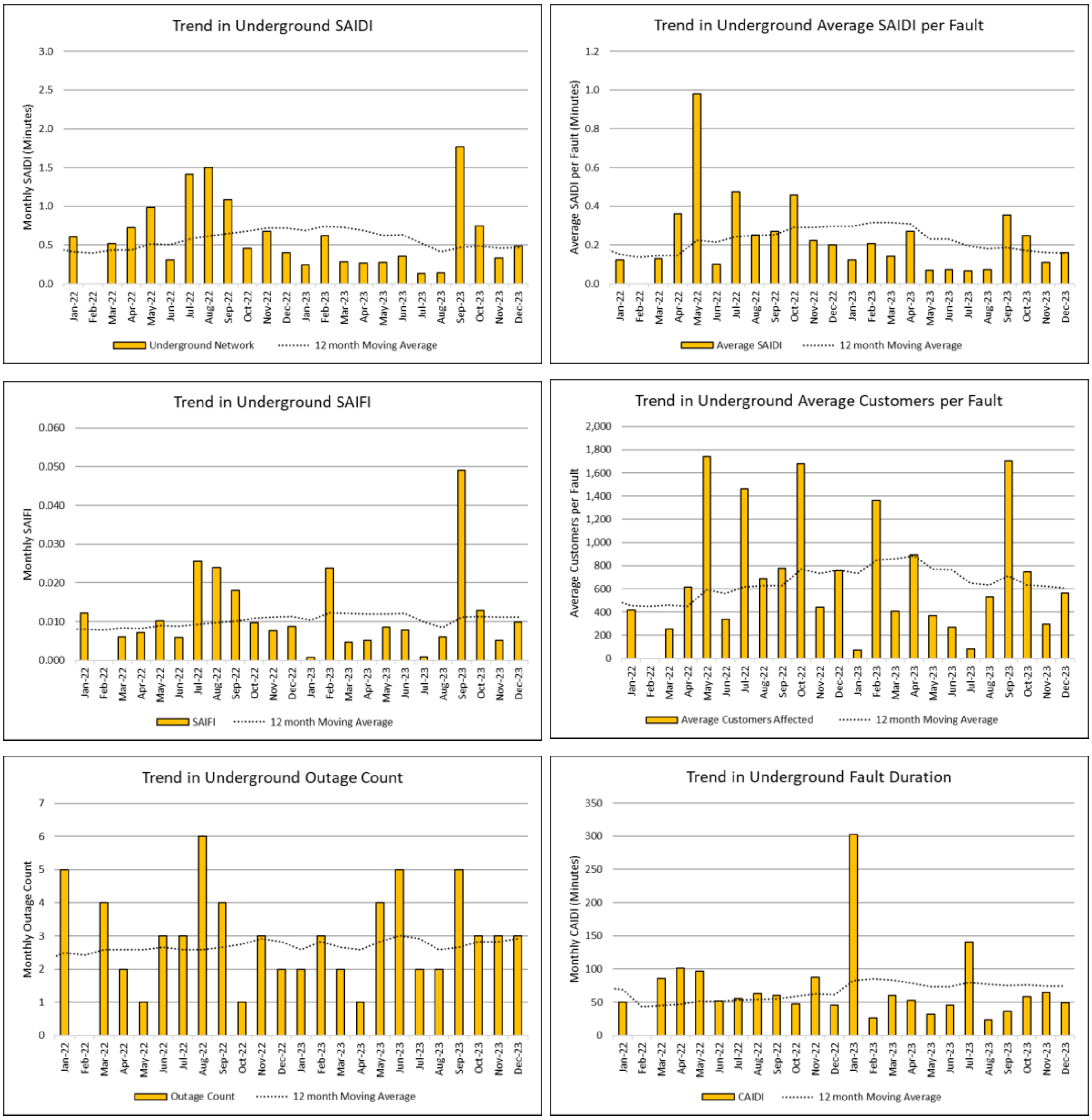


Figure 7-4 Example Trend Analysis from Monthly Reliability Report

7.3.3 Wind Effect Normalisation

The majority of Unplanned SAIDI on WELL's network occurs on the overhead sections of the network, with monthly performance being very dependent on weather conditions. To test whether overhead network performance has been better or worse than expected for the given wind conditions, the overhead outage count is normalised by maximum daily wind gust speed. This allows for proactive analysis of overhead performance: if the overhead network is underperforming at low and moderate wind speeds, any underlying issues can be identified and rectified proactively, rather than being repaired reactively after a strong wind event.

Two types of fault are considered:

- Overhead outages caused by equipment failure, and
- Overhead outages with non-asset causes that are likely to be related to wind: vegetation, windborne debris, and no fault found.

The criteria used for normalisation is the number of outages that occur on a day relative to the maximum wind gust recorded on that day. Outage count is considered to be a better metric than SAIDI for this model, as SAIDI is significantly affected by factors such as fault location and response.

Daily wind gust data is sourced from NIWA's Trentham weather station. Trentham was chosen as it is reasonably central to the area covered by WELL's overhead network. For simplicity, the model does not consider the effect of wind direction.

The baseline for the model is data from the DPP2 regulatory period, with the relationship between the average number of outages and daily wind gusts shown in Figure 7-5.

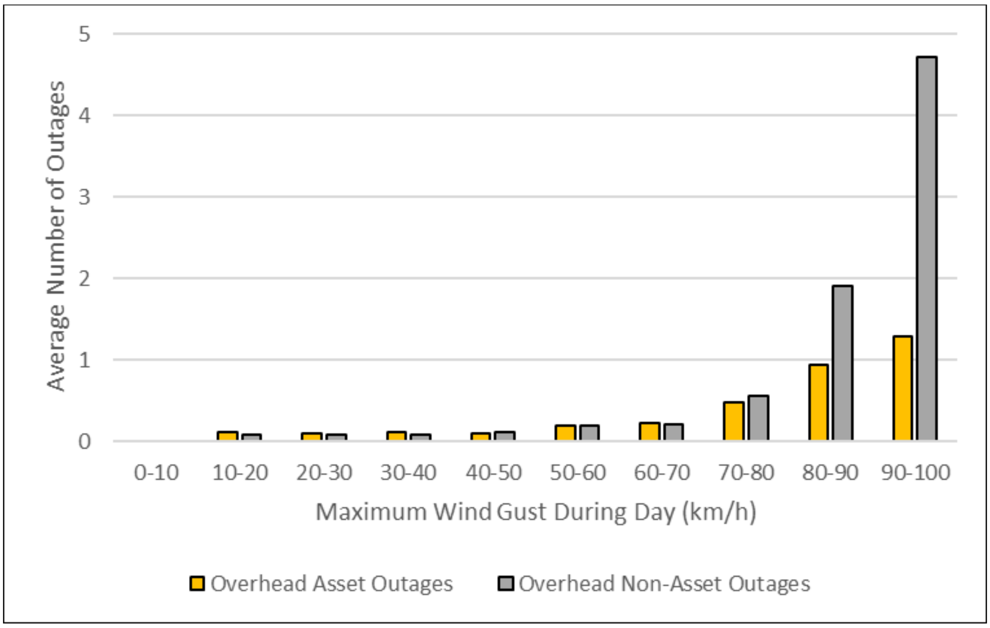


Figure 7-5 Overhead Outages by Maximum Daily Wind Gusts for DPP2

Applying these averages to the maximum daily wind gusts produces an expected number of annual outages for each year's wind conditions, which can then be compared to the actual number that was recorded. An example of this is shown in Figure 7-6, with the expected range being one standard deviation on either side of the expected average. These charts, presented to Management in the monthly reporting, show that the performance of the overhead network in 2023/24, although incurring more SAIDI than the Reference Period average as shown in Figure 7-3, has been reasonable given the wind speeds that have been experienced, and therefore does not indicate a deterioration in performance.

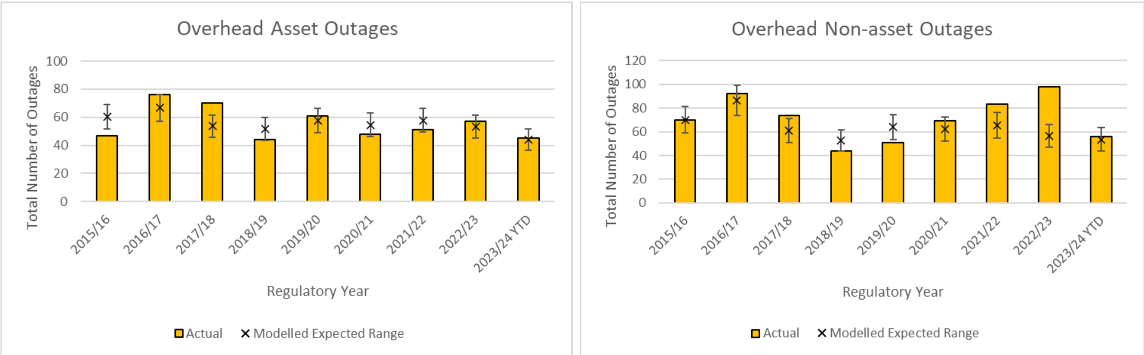


Figure 7-6 Example Overhead Outage Normalisation

7.3.4 Annual Feeder Performance Reviews

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

- Total SAIDI accrued by the feeder;
- Total SAIFI accrued by the feeder, and
- Total number of faults occurring on the feeder.

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

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

Each Worst Performing Feeder has a documented reliability improvement plan. These plans, which are controlled documents approved by the General Manager – Asset Management, contain the following information:

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

Each reliability improvement plan also includes a visualisation of the location and magnitude of the last three years' outages. An example is provided in Figure 7-7. This graphic highlights the specific areas of the feeder responsible for poor performance, identifies worst-served customers, and assists in the effective targeting of remedial actions.

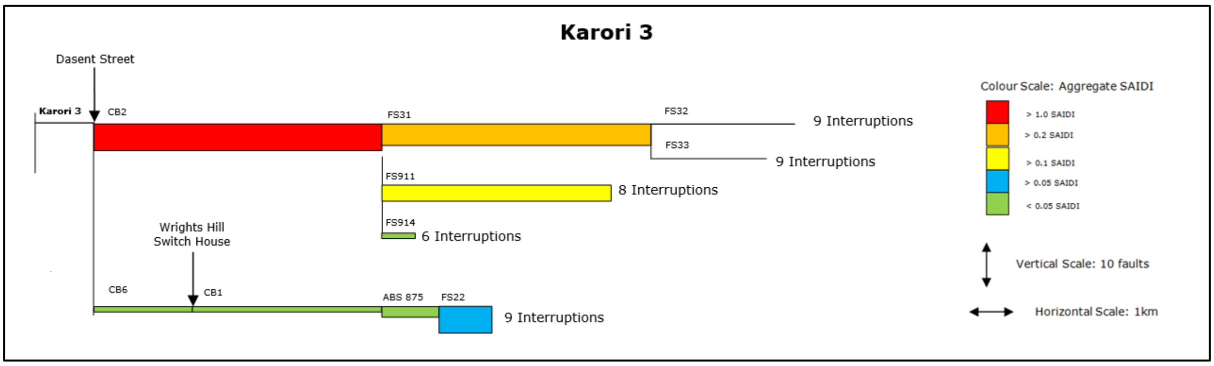


Figure 7-7 Example Feeder Outage Visualisation (Three Years)

7.4 Controls by Outage Cause

7.4.1 Planned Outages

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

Outage Peer Review

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

Temporary Generation

WELL has used temporary diesel generation to support planned outages since 2018, originally funded through the DPP2 reliability incentive scheme. The significant reduction in incentive rates for DPP3 has meant that while temporary generation is continuing to be used where appropriate, this is at a reduced level from prior years as the cost of providing generation will exceed the value placed on planned outages by the Commission unless it is of benefit to a large number of customers. WELL has updated its decision matrices that support the use of temporary generation for both planned and unplanned outages.

WELL is exploring modern alternatives to diesel generation as part of its commitment to decarbonisation.

7.4.2 Overhead Equipment

Outage Investigations

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

Conductor Sampling

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

7.4.3 Vegetation

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

Community Engagement

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

Risk-based Vegetation Control

WELL and Treescape utilise a risk-based approach to managing vegetation. The types and frequencies of vegetation surveys conducted by WELL are listed in Table 7-5. The annual vegetation management budget is based on the combination of surveys falling due, plus provisions for the estimated customer liaison required for cut or trim notices, and any first cuts that may be required.

Survey Type	Definition	Survey Frequency
Subtransmission Feeder	33 kV circuit, with or without underbuilt 11 kV or LV	2 years
Risk Feeder	Worst performing 11 kV feeders	Annual
HV Survey	11 kV circuit, with or without underbuilt LV	3 years
LV Survey	LV circuit	5 years
Rapid Response Survey	Out-of-cycle reactive survey	As required

Table 7-5 Vegetation Management Surveys

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

Covered Conductors

Covered conductors have been installed in areas prone to vegetation-related outages since 2018. WELL has purchased a quantity of conductor covers, which are available to be installed as areas of need are identified. These projects have proven effective at eliminating the reliability impact of wind-borne debris (e.g. branches and bark) in the areas where they have been installed, as shown in Figure 7-8. This chart shows that no vegetation outages have occurred in any of the areas where conductors have been installed after the installation of the covers.

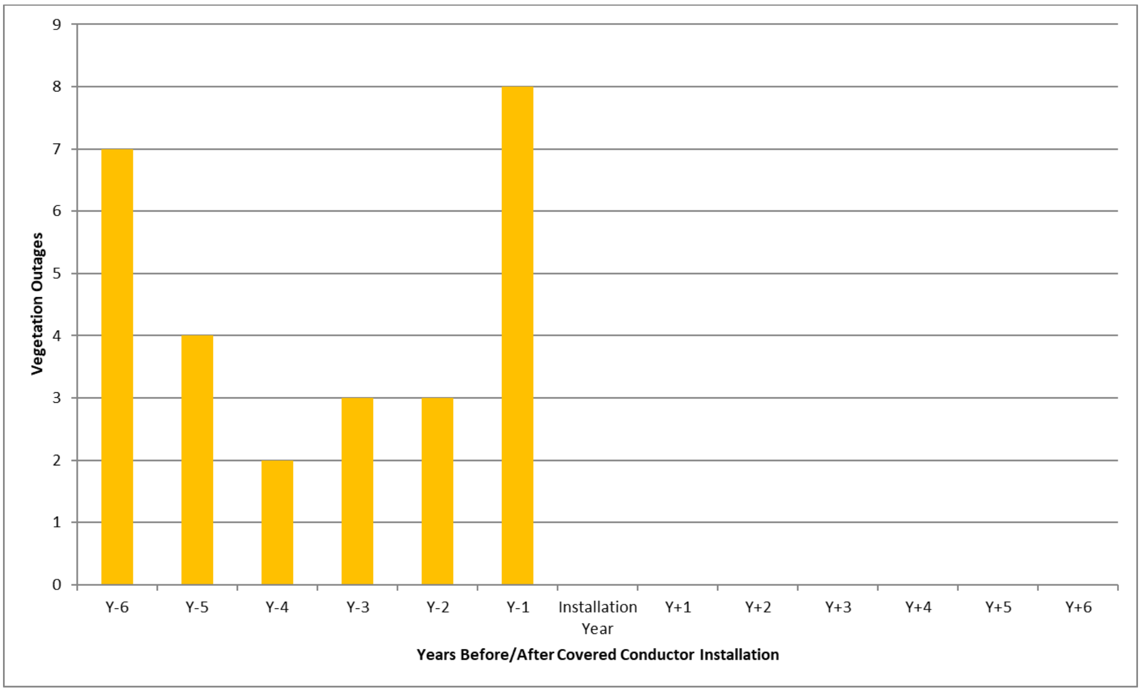


Figure 7-8 Aggregated Vegetation Outages in Covered Conductor Areas

7.4.4 Underground Equipment

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

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

7.4.5 Car versus Pole Incidents

WELL's approach to car versus pole incidents is to reduce the response time for making the incident site safe, which assists emergency services and reduces the impact on customers.

Section 8

Asset Lifecycle Management

8 Asset Lifecycle Management

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

In summary, the section covers:

- Asset fleet summary;
- Risk-based asset lifecycle planning;
- Asset health and criticality analysis;
- Maintenance practices;
- Asset maintenance and renewal programmes; and
- Asset replacement and renewal summary.

8.1 Asset Fleet Summary

A summary of the population for each of the Information Disclosure Requirements (IDR) categories and asset classes is shown in Table 8-1.

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Subtransmission	Subtransmission Cables	8.5.1	km	137.1
	Subtransmission Lines	8.5.3.2	km	56.8
Zone Substations	Zone Substation Transformers	8.5.2.1	number	52
	Zone Substation Circuit Breakers	8.5.2.2	number	368
	Zone Substation Buildings	8.5.2.3	number	30
Distribution and LV Lines	Distribution and LV Lines	8.5.3.3	km	1,661.4
	Streetlight Lines	8.5.3.3	km	818.3
	Distribution and LV Poles	8.5.3.1	number	40,029
Distribution and LV Cables	Distribution and LV Cables	8.5.4	km	3,005.5
	Streetlight Cables	8.5.4	km	11,149.2
Distribution Substations and Transformers	Distribution Transformers	8.5.5.1	number	4,558
	Distribution Substations	8.5.5	number	3,938

IDR Category	Asset Class	Section	Measurement Unit	Quantity
Distribution Switchgear	Distribution Circuit Breakers	8.5.6	number	1,230
	Distribution Reclosers	8.5.7.1	number	18
	Distribution Switchgear - Overhead	8.5.7.2	number	2,625
	Distribution Switchgear - Ground Mounted/Ring Main Units	8.5.6	number	2,345
Other Network Assets	Low Voltage Pits, Pillars, and Cabinets	8.5.6.1	number	22,502
	Protection Relays	8.5.8.2	number	1,454
	Load Control Plant	8.5.9.4	number	25

Table 8-1 Asset Population Summary

8.2 Risk-Based Asset Lifecycle Planning

Risk-based asset lifecycle planning consists of the following:

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

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

WELL takes a risk-based approach to asset lifecycle planning. The preventative maintenance programme is based on each maintenance task having a set cycle based on a known reliability history and is also influenced by any trends in the degradation of asset condition that may occur across a fleet. Corrective maintenance tasks identified during preventative maintenance are prioritised for repair according to severity and consequential risk to safety and network performance.

Standardised designs are used for high-volume assets, including overhead and underground construction, distribution substations, and distribution switchgear. This approach ensures:

- Familiarity for contractors, increasing the safety and efficiency of construction and operation;

- Procurement benefits, through reduced lead times and increased stock availability; and
- Economic benefits, as standard products generally have a lower cost than customised or non-standard ones.

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

Electricity distribution assets have a long but finite life expectancy and eventually require replacement. Premature asset replacement is costly as the service potential of the replaced asset is not fully utilised. Equally, replacing assets too late can increase the risk of safety incidents and service interruptions for customers. Asset replacement planning, therefore, requires the costs of premature replacement to be balanced against the risks of asset failure, public or contractor safety, and the deterioration of supply reliability that will occur if critical assets are allowed to fail in service. Hence, there is a balance to be found between the cost of maintaining an asset in service and the cost of replacing it.

Non-traditional solutions may become an important tool for asset lifecycle planning if they allow end-of-life assets to be decommissioned, and either not be replaced or be replaced with an option that is significantly cheaper than would otherwise be required. Non-traditional solutions have not yet been developed to the scale and reliability necessary for EDBs to be able to rely on them when making these kinds of asset management decisions, particularly given the consequences that the EDB would be subject to if non-delivery of a third-party non-traditional solution resulted in a Quality Path Breach. As a result, non-traditional solutions are not currently considered to be a viable option for WELL’s asset lifecycle planning.

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

8.3 Asset Health and Criticality Analysis

WELL uses the EEA Asset Health Indicator Guide - 2016. This methodology specifies a number of health indices for each asset class, which are rated on a scale of H5 to H1. Each scale represents a life-cycle phase with varying needs for, or benefits from, replacement. Each of the phases is termed and influenced by end-of-life drivers. The scale is shown in Figure 8-1.

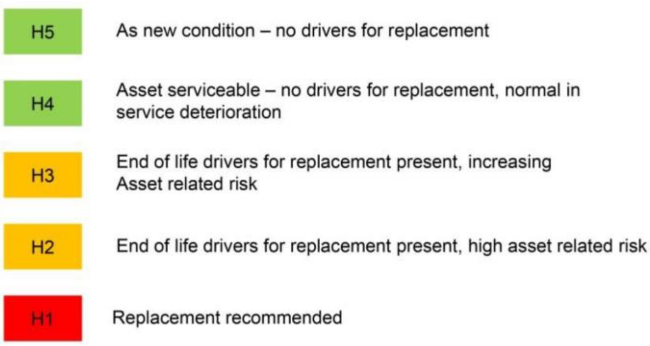


Figure 8-1 EEA Asset Health Indicator Scale

The overall Asset Health Indicator (AHI) is determined by its worst health index, further reduced by any indices scoring less than H4.

Asset Health Analysis does not take into account asset criticality or consequence of failure, so WELL developed an Asset Criticality Indicator (ACI) using the same methodology as Asset Health Analysis, incorporating factors such as the number of customers affected, load type and firm capacity. Asset criticality is scored on a scale of I5 (very low impact) to I1 (major impact).

The result of this analysis is a health-criticality matrix for each major asset class, with the asset location on the matrix indicating risk. Each number in the matrix gives the number of assets, in units or circuit km depending on the asset type, falling into that particular combination of health and criticality. As an example, the health-criticality matrix for power transformers on the WELL network is shown in Figure 8-2 and further discussed in Section 8.5.2.

		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			1	2			
	2.0				1			
	2.5			1	2			
	3.0			10	12	3	6	
	4.0			6	5	1	2	
Best Health	5.0							

Figure 8-2 Example Health-Criticality Matrix

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

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

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

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

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

8.4 Maintenance Practices

8.4.1 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.

8.4.2 Maintenance Categories

Maintenance is categorised into the following areas:

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

- **Vegetation management.** Planned and reactive vegetation work. WELL's approach to vegetation management is discussed in Section 7.4.3.

- **Routine and corrective maintenance and inspection.** This comprises:

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

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

    - **Value added.** Customer services such as high load escorts, standover provisions for third-party contractors, and provision of asset plans for the 'beforeUdig' programme, to prevent third-party damage to assets.

- **Asset replacement and renewal.** Reactive repairs and replacements that do not meet the criteria for capitalisation.

The forecast maintenance expenditure for 2024-2034 is summarised by asset class throughout this section.

8.5 Asset Maintenance and Renewal Programmes

This section describes WELL's approach to preventative maintenance and inspections. It also sets out the maintenance activities undertaken for each asset class and commentary is provided on renewal and refurbishment policies or criteria plus known systematic issues. The IDR categories (with their associated asset classes) covered are:

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

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

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

8.5.1 Subtransmission Cables

Fleet Overview

WELL owns approximately 138 km of subtransmission cables operating at 33 kV. These comprise 50 circuits connecting Transpower GXPs to WELL's zone substations. Approximately 35 km of subtransmission cable is XLPE construction and requires little maintenance. The remainder is of paper-insulated construction, with a significant portion of these cables being fluid- or gas-filled. A section of the subtransmission circuits supplying the Ira Street zone substation is oil-filled PIAS (paper-insulated aluminium sheath) cables rated for 110 kV but operating at 33 kV. There are also two 33 kV cables operating at 11 kV which are treated as subtransmission cables supplying Titahi Bay substation. Each circuit is modelled using WELL's Asset Health and Criticality systems. The lengths and age profile of this asset class are shown in Table 8-2 and Figure 8-3.

Construction	Design Voltage	Percentage	Quantity
Paper Insulated, Oil Pressurised	33 kV	28.5%	41.6 km
Paper Insulated, Gas Pressurised	33 kV	30.5%	44.4 km
Paper Insulated	33 kV	5.2%	7.5 km
XLPE Insulated	33 kV	23.9%	34.9 km
Paper Insulated, Oil Pressurised	110 kV	6.0%	8.7 km
Paper Insulated, Oil Pressurised	11 kV	5.9%	8.6 km
Total			**145.8 km**

Table 8-2 Summary of Subtransmission Cables

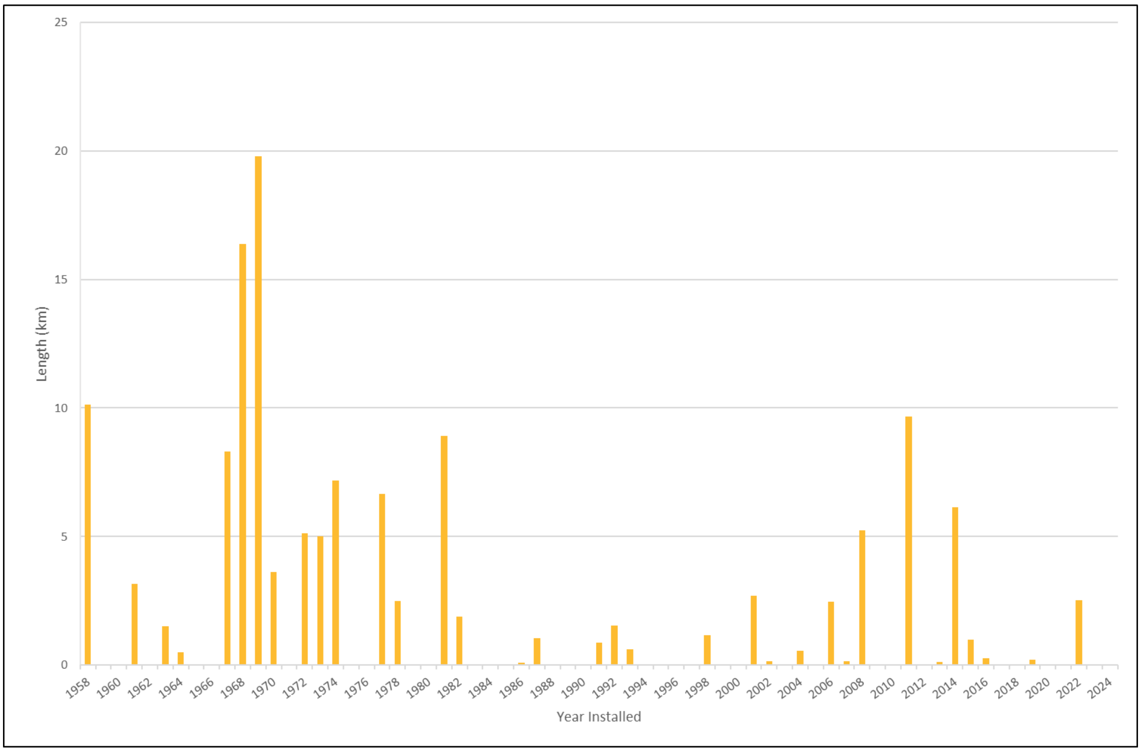


Figure 8-3 Age Profile of Subtransmission Cables

Fleet Objectives

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

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

Table 8-3 Fleet-Specific Objectives for Subtransmission Cable Fleet

Maintenance Activities

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

Activity	Description	Frequency
Cable sheath tests	Testing of cable sheath and outer servings, continuity of sheath, cross-bonding links and sheath voltage limiters.	2 yearly
Cable fluid injection equipment inspection	Inspection and minor maintenance of equipment in substations, kiosks and underground chambers.	6 monthly
Subtransmission route regular patrol	Patrol of cable route; replace missing or damaged cable markers.	Weekly

Table 8-4 Inspection and Routine Maintenance Schedule for Subtransmission Cables

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

Objective condition assessment on cables with fluid pressurisation is limited to leakage rates as a number of cable condition assessment techniques, including partial discharge testing, are not applicable to these types of cables. The main mode of failure of these cables is stress on the joints and resulting failure, and 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 historical fault information for each cable is used to assess and prioritise the need for cable replacement, as well as determine the strategic spares to be held. Strategic spares for subtransmission cables are outlined in Table 8-5.

Strategic Spares	
Medium lengths of cable	Medium lengths of fluid-filled cable are held in storage to allow the replacement of short sections following damage, to allow repairs without requiring termination and transition to XLPE cable.
Standard joint fittings	Stock is held to repair standard fluid-filled joints. A minimum stock level is maintained.
Termination/transition joints	Two gas-to-XLPE cable transition joints are held in storage to allow the replacement of failed transition joints or damaged sections of gas-filled cables with non-pressurised XLPE cables where necessary.
Emergency Overhead Line Spares	WELL has designed alternative overhead line routes for all fluid-filled subtransmission cables to prepare for the possibility of significant damage post a major earthquake. WELL has procured sufficient spares to construct 19km of emergency overhead 33kV lines.

Table 8-5 Spares for Subtransmission Cables

Cable Condition and Failure Modes

Gas-filled cables

Gas-filled cables are pressurised with nitrogen. They have been in use internationally since the 1940s but have largely been phased out in favour of fluid-filled or solid-insulated cables. WELL is the only distributor that still has gas-filled cable in service in New Zealand, although there are still some in Australia. Gas cables require close monitoring of cable performance to manage any deterioration and consequent reduction in levels of service. Some of these cables have been repaired as a result of third-party damage or after gas leaks have been found.

Figure 8-4 shows the trend in gas leakage from WELL's gas-filled cables for the 12 months to the end of February 2024.

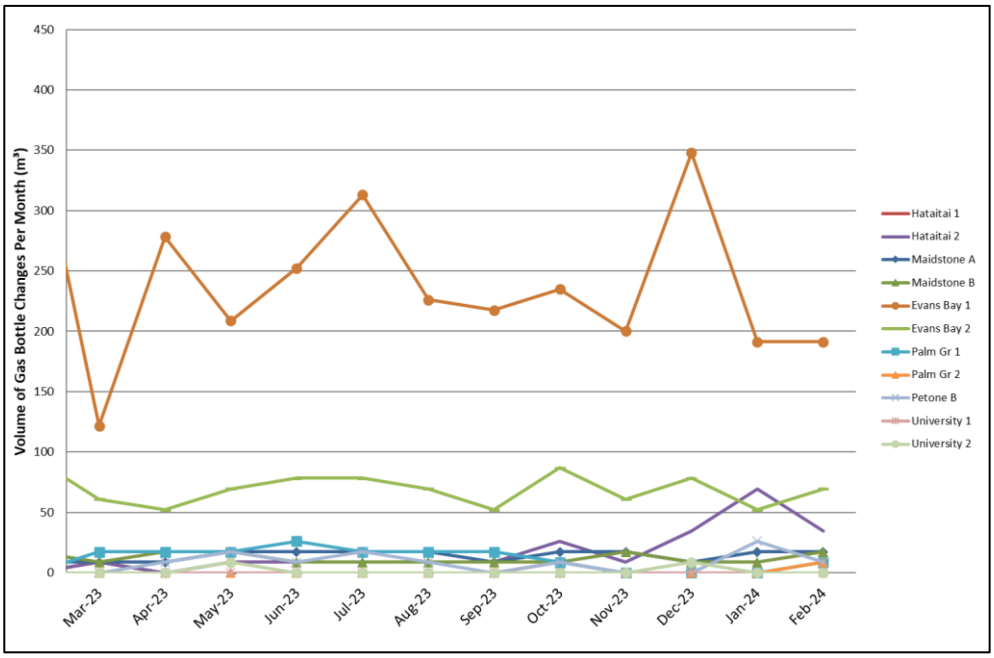


Figure 8-4 Monthly Gas-Filled Cable Leakage

Fluid-filled Cables

Fluid-filled cables were installed in the WELL network from the mid-1960s until 1991. Some circuits have experienced fluid leaks but in general, the condition of the cables remains good for their age. The environmental impacts of leaks are mitigated through the use of biodegradable cable fluid.

Figure 8-5 shows the trend in fluid leakage from WELL's fluid-filled cables for the 12 months to the end of February 2024.

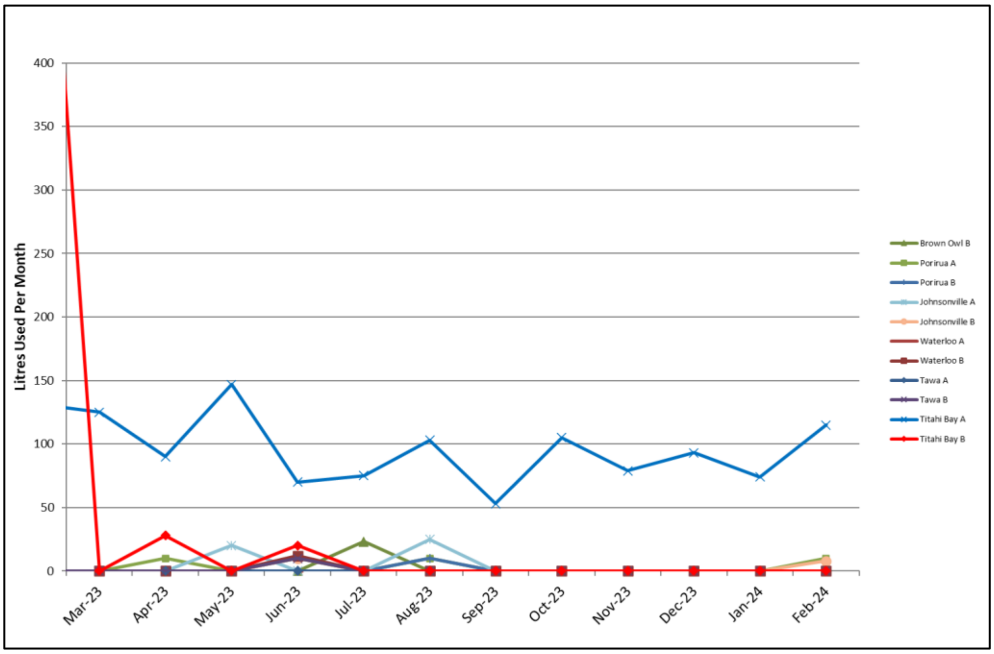


Figure 8-5 Monthly Fluid-Filled Cable Leakage

Paper and Polymeric Cables

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

Forecast Future Condition

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

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

Subtransmission Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis results in the health-criticality matrix shown in Figure 8-6, with individual circuit scores and ratings being presented in Table 8-6. 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				5.1			
Asset Health	1.5				18.4		3.6	
	2.0							
	2.5			23.9	66.6			
	3.0							
	4.0			2.5	3.4	10.3		
Best Health	5.0						13.6	

Figure 8-6 Subtransmission Cable Circuit Health-Criticality Matrix (km)

Subtransmission Circuit	Primary Type	AHI	ACI	Rating
Evans Bay 1	Gas	1.0	2.9	
University 1 & 2	Gas/XLPE	1.8	1.9	
Titahi Bay A & B (11kV)	Fluid	1.6	2.9	
Evans Bay 2	Gas	1.8	2.8	
Tawa A & B	Fluid	1.9	2.9	
Frederick Street 1 & 2	XLPE	5.0	1.8	
Palm Grove 1 & 2	XLPE	5.0	1.8	
The Terrace 1 & 2	XLPE	5.0	1.9	
Maidstone A & B	Gas	2.6	2.9	
Karori 1 & 2	Gas	2.7	2.7	
Hataitai 1 & 2	Gas	2.7	2.9	
Johnsonville A & B	Fluid	2.7	2.9	
Porirua A & B	Fluid	2.7	2.9	
Ira Street 1 & 2	Fluid	2.8	2.9	
Korokoro A & B	Fluid	2.8	2.9	
Kenepuru A & B	Fluid	2.9	2.9	
Waikowhai Street A & B	Gas	2.7	3.0	
Trentham A & B	Fluid	2.8	3.0	
Waitangirua A & B	Fluid	2.8	3.0	
Brown Owl A & B	Fluid	2.9	3.0	
Naenae A & B	Fluid	2.9	3.0	
Waterloo A & B	Fluid	2.9	3.0	
Moore Street 1 & 2	XLPE	4.0	2.0	
Wainuiomata A & B	PILC	4.0	2.0	
Ngauranga A & B	XLPE	4.0	2.9	
Seaview A & B	PILC	4.0	2.9	
Gracefield A & B	PILC	4.0	3.0	
Mana	XLPE	4.0	3.0	
Plimmerton	XLPE	4.0	3.0	

Table 8-6 Health Criticality Scores for Subtransmission Cable Circuits

Outcome of Asset Health and Criticality Analysis

The highest-priority subtransmission cable circuits, and significant changes since the 2023 AMP, are discussed below.

Evans Bay

The Evans Bay subtransmission circuits were installed in 1958 and are the oldest gas cables on the network. The cables are leaking, however, performance has been stable for the last three years. Contingency plans are in place to mitigate various possible outage scenarios.

A project is underway to install a 33kV bus at Evans Bay which will be supplied from the two Ira Street cables (which run through the Evans Bay substation compound) and Evans Bay Circuit 2. This will create a subtransmission ring with sufficient capacity to supply both Evans Bay and Ira Street zone substations with N-1 security and reduce the criticality of the Evans Bay cables. Further detail of this project is provided in Section 9.4.

The longer-term plan is to run new cables to Evans Bay within the next 10 years, preferably in conjunction with planned transport projects.

University

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

Both circuits experienced faults in their XLPE sections during 2015, and laboratory analysis of cable samples revealed issues around premature ageing of the cable insulation due to thermal degradation. Full replacement of both the gas-filled and XLPE cables was expected to be required in approximately 10 years. A feasibility study of replacement options was undertaken in 2022, and replacement is planned to occur in 2026.

Titahi Bay

In August 2021 it was identified that an ongoing leak on the Titahi Bay A cable, operated at 11kV, had become more serious and required action. Location work proceeded through the remainder of the year, with the leak being found and repaired in December 2021. Subsequent to this repair, a further leak occurred on the Titahi Bay B cable that was repaired in February 2023. The sequence of leaks occurring on these cables over the last five years indicates that the cables are approaching end-of-life, and work to replace these two circuits has now commenced in conjunction with a Porirua City Council urban cycleway project.

Tawa

Condition assessment using an Uncrewed Aerial Vehicle (UAV) in 2020 identified corrosion on the cable trifurcating boxes at Bing Lucas Drive that had not been visible to routine ground-based inspections. The damage was temporarily repaired, and it is expected that the cables would require replacement, however a permanent repair solution has been developed to allow the cables to remain in service until 2030. Demand growth in the area is expected to trigger replacement of the cables sooner than that, as discussed in Section 9.5.

Karori

The Karori subtransmission cables are currently in good health with no history of poor performance. They are however the gas-filled cables with the highest Asset Criticality Index after University, due to the substation's location on the periphery of the network, with limited 11 kV ties to neighbouring zone substations. Replacement of these cables is proposed to occur by 2029.

Renewal and Refurbishment

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

Significant projects for the renewal of subtransmission cables over the next 12 months are listed in Table 8-7.

Project	Description
Titahi Bay 33kV Cable	Commencement of ducting along the replacement cable route.

Table 8-7 Subtransmission Cable Projects for 2024/25

Expenditure Summary for Subtransmission Cables

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

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
University Cable Replacement	512	3,600	-	-	-	-	-	-	-	-
Titahi Bay Cable Replacement	1,000	8,900	-	-	-	-	-	-	-	-
Karori Cable Replacement	-	-	-	8,500	10,000	-	-	-	-	-
Maidstone Cable Replacement	-	-	-	-	-	-	10,000	10,000	-	-
Waterloo Cable Replacement	-	-	-	-	-	-	-	-	10,500	-
Capital Expenditure Total	**1,512**	**12,500**	**-**	**8,500**	**10,000**	**-**	**10,000**	**10,000**	**10,500**	**-**
Preventative Maintenance	103	102	101	101	101	100	100	100	99	98
Corrective Maintenance	560	560	560	560	560	560	560	560	560	560
Operational Expenditure Total	**663**	**663**	**662**	**661**	**661**	**660**	**660**	**660**	**659**	**658**

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

8.5.2 Zone Substations

8.5.2.1 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 the University Zone Substation (manufactured in 1986). Even so, most power transformers are in very good condition due to their being mostly indoors and loaded to less than 50% of their nameplate rating. The age profile for zone substation transformers is shown in Figure 8-7.

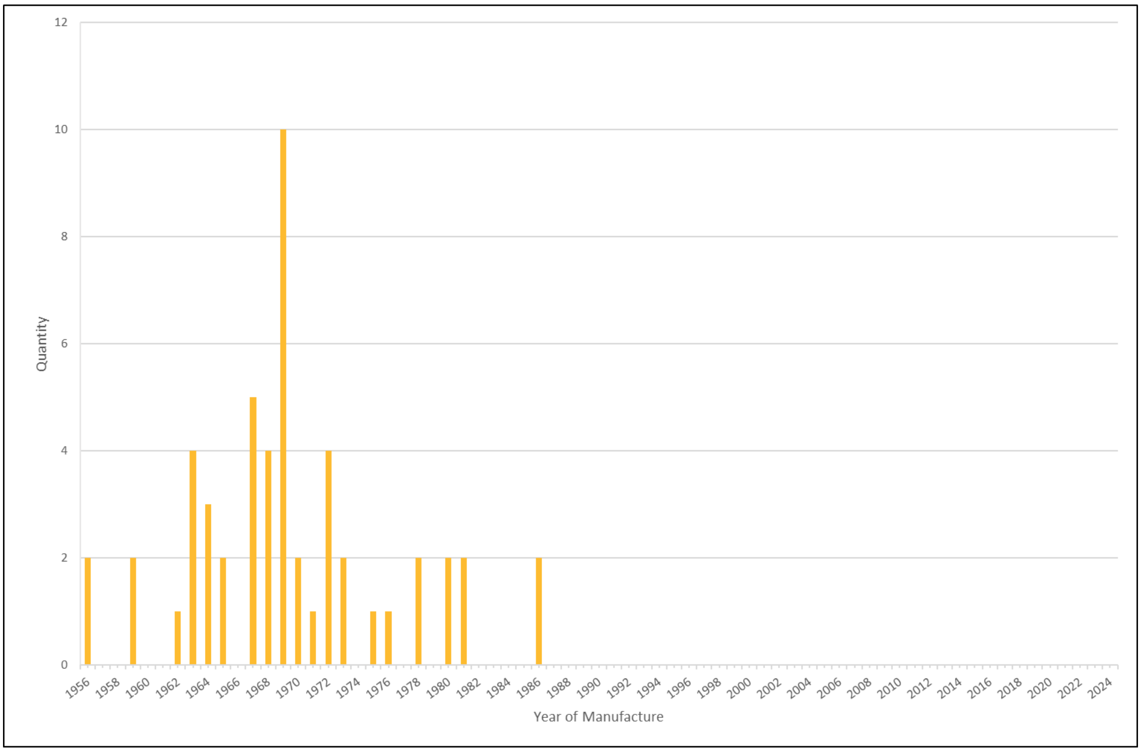


Figure 8-7 Age Profile of Zone Substation Transformers

The mean age of the transformer fleet is 53 years.

Fleet Objectives

In addition to WELL's broader asset management objectives that apply across the entire network, WELL has fleet-specific objectives for the power transformer fleet as detailed in Table 8-9:

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

Table 8-9 Fleet-Specific Objectives for Power Transformer Fleet

Maintenance Activities

Routine planned inspection, testing and maintenance activities are undertaken on zone substation power transformers as detailed in Table 8-10:

Activity	Description	Frequency
Transformer main tank oil test	Dissolved gas analysis (DGA) testing of transformer main tank oil including furan analysis.	Annually
Transformer tap changer oil test	Dissolved gas analysis (DGA) testing of transformer tap changer oil.	Annually
Transformer maintenance, protection and AVR test	De-energised transformer maintenance, inspection and testing of the transformer, and diagnostic tests as required. Hot collar testing of bushings if appropriate. Gas injection for testing of Buchholz. Testing of temperature gauge and probe. Confirmation of correct alarms. Test AVR and ensure correct operation and indications.	4 yearly
OLTC maintenance	Programmed maintenance of OLTC.	4 yearly

Table 8-10 Inspection and Routine Maintenance Schedule for Zone Substation Transformers

Strategic Spares

WELL holds critical spares for the power transformers and tap changers as detailed in Table 8-11.

Strategic Spares	
Tap changer fittings	WELL holds a number of critical and maintenance spares for the tap changers on zone substation transformers, typically contacts and related components. These components have high wear and are eroded by arcing during operation. Where excessive wear is noted during maintenance, spares are ordered and held in stock for that model of tap changer. Spares are still available for most models on the network, and if necessary, spares can be re-manufactured by third-party suppliers.
Transformer misc. fittings	Various other transformer fittings have been identified and held for sites where having a transformer out of service for a prolonged period is unacceptable. Fittings include Buchholz relays, high-voltage bushings etc. If major repairs are needed, a unit will be swapped out.
Spare transformers	One spare power transformer is located at the 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	WELL owns two mobile substations that comprise trailer-mounted 10MVA 33/11kV transformers and containerised 33kV and 11kV switchgear.

Table 8-11 Spares Held for Zone Substation Transformers

Transformer Condition

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

Oil analysis provides an estimated Degree of Polymerisation (DP) value for the paper insulation which provides an initial overview of the transformer condition. Furan analysis is undertaken with DGA oil tests, which shows 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.

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

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

Transformer Asset Health and Criticality Analysis

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

		Lowest Impact		**Asset Criticality**			Highest Impact	
Asset Health		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
	1.5			1	2			
	2.0				1			
	2.5			1	2			
	3.0			10	12	3	6	
	4.0			6	5	1	2	
Best Health	5.0							

Figure 8-8 Power Transformer Health-Criticality Matrix

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

Table 8-12 Health Criticality Scores for Power Transformers

Outcome of Asset Health and Criticality Analysis

A large number of units are in better health than would be expected for their age. This is due to a number of factors, particularly the proportion of units located indoors and therefore less vulnerable to corrosion, and loading on transformers being kept below 50% for security reasons. Exceptions to this are noted below.

Evans Bay

The transformers at Evans Bay were installed in 1959 and have the lowest health indices in the network. These transformers have experienced an increasing number of problems in recent years, mostly relating to the mechanical performance of the tap changer and excessive leaks due to the 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 project to replace these transformers is underway for completion in 2024.

Mana

The Mana transformer is a South Wales unit that was manufactured in 1963 and has exhibited a low estimated DP value based on a Furan Analysis of 400. The DGAs on this unit show no concerning signs in terms of combustible gases, carbon monoxide, or carbon dioxide. Online monitoring has been fitted to the transformer to provide a more detailed estimate of end-of-life, and this is indicating that replacement will be required at the end of the period covered by this AMP.

Palm Grove

The Palm Grove transformers are in good condition but have high criticality due to the peak loading and number of customers supplied by the substation. Their asset health is marked down slightly due to the noise created by their forced cooling and the proximity of residential neighbours. The proposed development path outlined in Section 9 indicates that the most cost-effective option to manage the transformer health in the short term is to deload the transformers on the 11 kV system during the three days a year that the load exceeds the transformer rating while planning for reinforcement of the subtransmission supply into Newtown by 2026.

Ngauranga

Ngauranga has the oldest power transformers installed in WELL's network. These transformers are generally reliable but have experienced problems with the tap changer diverter switches in the past. These issues will be monitored and corrective repairs undertaken as required. It is expected that replacement due to condition would be required towards the end of the planning period, however as identified in Section 9.5, replacement of the transformers is planned for 2026 due to capacity constraints.

Tawa

The Tawa transformers are currently in an acceptable condition, however, DP trending indicates that they are ageing faster than similar transformers in the network. The DP is continuing to be monitored, however it is expected that the units will be replaced under System Growth due to capacity as discussed in Section 9.5.

University 1

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

Renewal and Refurbishment

Where a transformer is identified for relocation, refurbishment is generally performed if it is economical 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 economical.

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, and
- Transformer replacements at Evans Bay and Mana zone substations.

Transformer replacement projects that are triggered by capacity constraints rather than asset health and criticality, including Ngauranga and Porirua, are detailed in Section 9.

Where a power transformer is approaching, or at, its service half-life, subject to condition assessment results, a refurbishment including mechanical repairs, drying, and tightening of the core and associated electrical repairs will be considered if supported by a business case. For power transformers in the WELL network, the testing and inspection programme will aid in getting the best life from the transformer and also ensure optimal timing for unit replacement.

Significant projects for the renewal of power transformers over the next 12 months are listed in Table 8-13.

Project	Description
Evans Bay	Complete installation of replacement units.

Table 8-13 Power Transformer Projects for 2024/25

Expenditure Summary for Power Transformers

Table 8-14 details the expected expenditure on power transformers by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Evans Bay Transformer Replacements	1,720	-	-	-	-	-	-	-	-	-
Mana Transformer Replacement	-	-	-	-	-	-	-	-	-	5,000
Capital Expenditure Total	**1,720**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**5,000**
Preventative Maintenance	345	345	345	345	345	345	345	345	345	345
Corrective Maintenance	120	120	120	120	120	120	120	120	120	120
Operational Expenditure Total	**465**	**465**	**465**	**465**	**465**	**465**	**465**	**465**	**465**	**465**

Table 8-14 Expenditure on Power Transformers ($K in constant prices)

8.5.2.2 Zone Substation Switchboards and Circuit Breakers

Fleet Overview

11 kV circuit breakers are used in zone substations to control the power injected into the 11 kV distribution network. There are 367 circuit breakers located at zone substations on the WELL network. The most common single type is the Reyrolle Pacific type LMT circuit breaker. An age profile of these circuit breakers is shown in Figure 8-9.

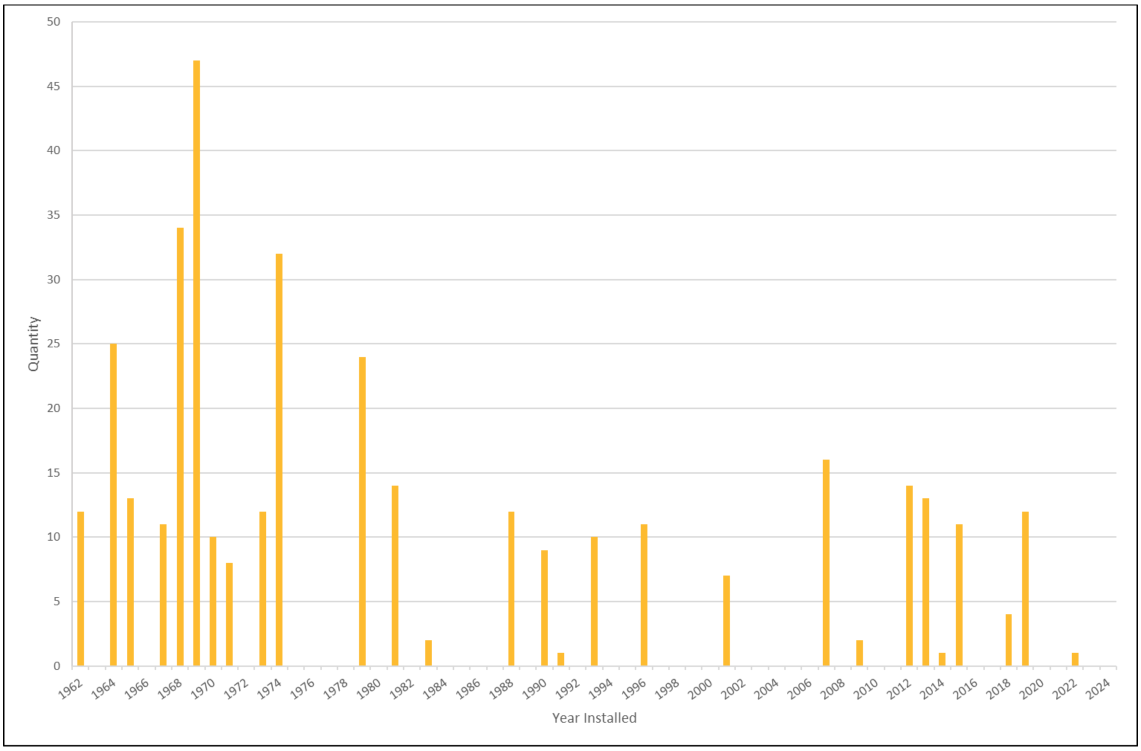


Figure 8-9 Age Profile for Zone Substation Circuit Breakers

The average age of zone substation circuit breakers in the Wellington Network is approximately 41 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 29 years. Originally manufactured in the 1960s, they were installed in 1993 when the substation was constructed. These breakers will be decommissioned when the transformers are replaced in 2025. Until then, a spare unit has been obtained from Transpower.

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

Table 8-15 Summary of Zone Substation Circuit Breakers

Manufacturer	Breaker Type	Quantity
Nissin	Oil (33 kV)	2
Reyrolle (RPS)	Oil	257
	Vacuum	93
Siemens	SF_6	16
Total		**368**

Table 8-16 Summary of Zone Substation Circuit Breakers by Manufacturer

Fleet Objectives

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

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

Table 8-17 Fleet-Specific Objectives for Zone Substation Circuit Breaker Fleet

Maintenance Activities

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

Activity	Description	Frequency
General Inspection of 33 kV Circuit Breaker	Visual inspection of equipment and condition assessment based on 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 on 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, and 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 the condition of interrupter bottles where possible, clean, and return to service. Trip timing test before and after service.	4 yearly

Activity	Description	Frequency
11 kV Switchboard Major Maintenance	Full or bus section shutdown, removal of all busbar and chamber access panels, cleaning and inspecting all switchboard fixed portion components, and undertaking condition and diagnostic tests as required. Maintain VTs and CTs. Return to service.	8 yearly
11 kV Circuit Breaker – Annual Operational Check	Backfeed supply, and 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 8-18 Inspection and Routine Maintenance Schedule for Zone Substation Circuit Breakers

Strategic Spares

Given the high number of circuit breakers in service on the WELL network, it is important to keep adequate quantities of spares to enable fast repair of defects. The largest quantity of circuit breakers on the network is the Reyrolle type LMT, which is used predominantly at zone substations, and WELL holds large numbers of spares for these circuit breakers. Furthermore, the RPS (formerly Reyrolle Pacific) switchgear factory is located in Petone which means that spares are available within short timeframes if required for LMT-type switchgear. An overview of strategic spares held for circuit breakers is shown in Table 8-19.

Strategic Spares	
Circuit breaker trucks	At least one circuit breaker truck of each rating (or the maximum rating where it is universal fitment) is held for each type of withdrawable circuit breaker on the network.
Trip/Close coils	Spare coils are 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.
33 kV Nissin KOR Circuit Breaker	One complete unit held as a spare for the Ngauranga 33 kV circuit breakers
Mobile switchboard	WELL owns a containerised 11kV mobile switchboard.

Table 8-19 Spare Parts Held for Circuit Breakers

Switchgear Condition and Failure Modes

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

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

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

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

Reyrolle LMT - Partial Discharge (PD)

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

Older LMT circuit breakers are prone to developing partial discharge on resin current transformers and bushings, which can be cost-effectively resolved by the refurbishment of these components using a retrofit kit. 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 of issues with LMT.

Circuit Breaker Asset Health and Criticality Analysis

The Asset Health and Criticality Analysis results are shown in the health-criticality matrix in Figure 8-10, with individual switchboard scores and ratings being presented in Table 8-20.

		Lowest Impact			Asset Criticality		Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
	1.5				2			
	2.0				1	1	1	
Asset Health	2.5			4	6			
	3.0			3	5	1	2	
	4.0			1				
Best Health	5.0			1	1		3	

Figure 8-10 Zone Substation Switchboard Health-Criticality Matrix

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

Table 8-20 Health-Criticality Scores for Zone Substation Switchboards

Outcome of the Asset Health Analysis

Frederick Street

The Reyrolle LMT switchboard at Frederick Street has had a number of stages of PD mitigation work since 2015. Subsequent PD testing has indicated that this ongoing work had been successful, it has also shown adjacent circuit breakers with high PD levels that have been masked previously. Further PD mitigation works will occur on these adjacent circuit breakers involving the two-breaker incomer for power transformer T1.

Kenepuru

Partial discharge mitigation work at Kenepuru is now complete. The health of the switchboard will be reassessed following its next PD survey.

Mana and Hataitai

Maintenance work at Mana and Hataitai has not yet been successful in eliminating the partial discharge at these sites. Further investigation is being undertaken.

Moore Street

Partial discharge has been detected on three circuit breakers. This will be addressed by the installation of retrofit components in 2024.

Renewal and Refurbishment

WELL's fleet of zone substation circuit breakers is generally in good condition. Assuming that the ongoing programme to mitigate partial discharge issues as they are identified continues to be successful, no zone substation circuit breakers are expected to require replacement for health reasons during the next five years. During the period 2025-2030, three-zone substation switchboards will exceed 60 years of age. There is no indication that the replacement of these switchboards needs to be driven purely by age, however, their condition will continue to be monitored through routine inspections and maintenance.

Significant projects for the renewal of zone substation circuit breakers over the next 12 months are listed in Table 8-21.

Project	Description
Frederick Street	Partial discharge migration on the T1 incomer
Moore Street	Partial discharge mitigation of three feeder breakers.

Table 8-21 Zone Substation Circuit Breaker Projects for 2024/25

Expenditure Summary for Zone Substation Circuit Breakers

Table 8-22 details the expected expenditure on zone substation circuit breakers by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Partial Discharge Mitigation	540	270	270	270	270	270	270	270	270	270
Capital Expenditure Total	**540**	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**	**270**
Preventative Maintenance	100	100	100	100	100	100	100	100	100	100
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**	**120**

Table 8-22 Expenditure on Zone Substation Circuit Breakers
($K in constant prices)

8.5.2.3 Zone Substation Buildings and Equipment

Fleet Overview

There are 27 zone substation buildings and three major 11 kV switching station buildings that function as zone 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.

All WELL's zone substation buildings have a seismic rating of at least 67% of the New Building Standard (NBS) at Importance Level 4.

The age profile of the major substation buildings is shown in Figure 8-11. The average age of the buildings is 51 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.

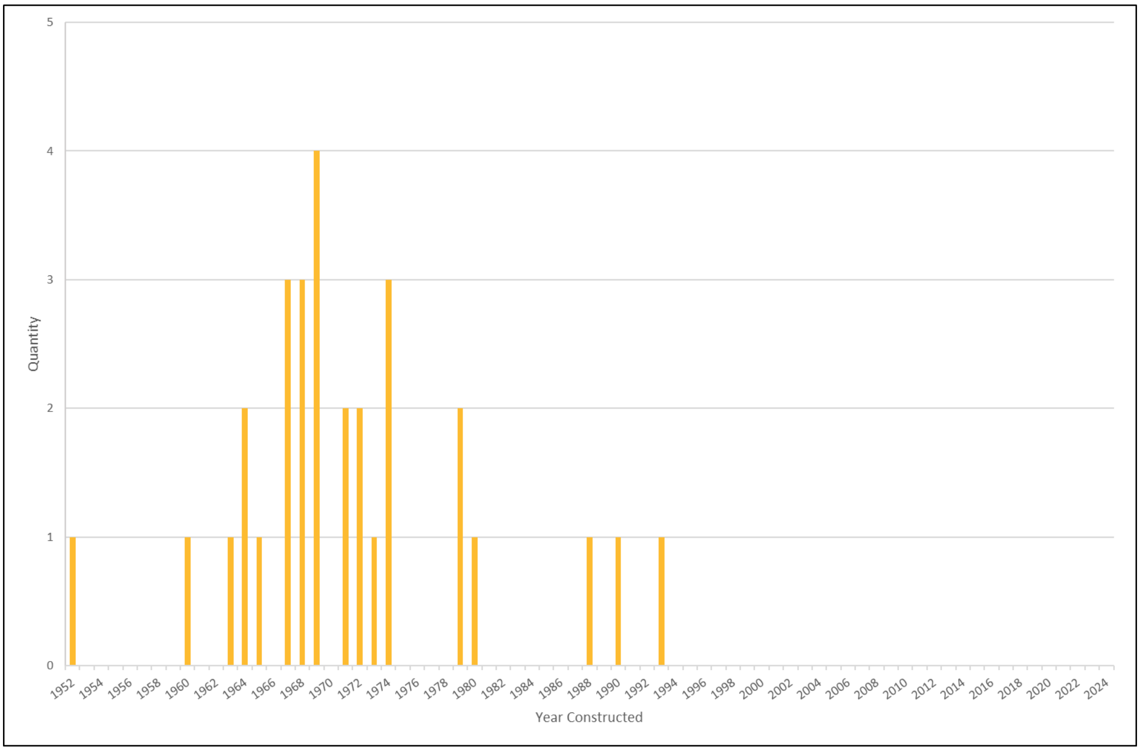


Figure 8-11 Age Profile of Major Substation Buildings

Fleet Objectives

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

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

Table 8-23 Fleet-Specific Objectives for Zone Substation Buildings

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on zone substation buildings and related equipment:

Activity	Description	Frequency
Zone Substation - Routine Inspection	Routine visual inspection of zone substation to ensure asset integrity, safety and security. Record and report defects, and undertake minor repairs as required. Thermal inspection of all equipment, handheld PD and Ultrasonic scan. Inspect and maintain oil containment systems, and inspect and test transformer pumps and fans.	3 monthly
Grounds maintenance	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 systems.	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 8-24 Inspection and Routine Maintenance Schedule for Zone Substations and Equipment

Routine zone substation inspections are undertaken quarterly and include the building and other assets such as lighting, fire systems, security systems, fans, heaters and safety equipment. The grounds and ripple injection spaces are also maintained to ensure access, security, condition and safety. Where appropriate, annual building warrant of fitness inspections are carried out and any defects are rectified. Building maintenance varies depending on 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 the ongoing reliability of the 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.

Expenditure Summary for Zone Substation Buildings

Table 8-25 details the expected CAPEX expenditure on zone substation buildings by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Asset Replacement and Renewal CAPEX	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	100	100	100	100	100	100	100	100	100	100
Corrective Maintenance	305	305	305	305	305	305	305	305	305	305
Operational Expenditure Total	**405**	**405**	**405**	**405**	**405**	**405**	**405**	**405**	**405**	**405**

Table 8-25 Expenditure on Zone Substation Buildings ($K in constant prices)

8.5.3 Overhead Lines

8.5.3.1 Poles

The total number of poles owned by WELL, including subtransmission distribution lines and low voltage lines, is 40,029. Of this number, 18.7% are wooden poles and 80.8% are concrete poles. The remaining 0.5% of poles are fibreglass or steel. Another 16,721 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 8-26.

Pole Owner	Wood	Concrete/Other	Total
WELL	7,473	32,556	40,029
Customer	6,100	599	6,699
Chorus	7,355	363	7,718
Wellington City Council	1,370	1,068	2,438
Total	**22,298**	**34,586**	**56,884**

Table 8-26 Summary of Poles

The average age of concrete/ other poles is 30 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. 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 require hand-carrying of replacement poles.

An age profile of poles owned by WELL is shown in Figure 8-12.

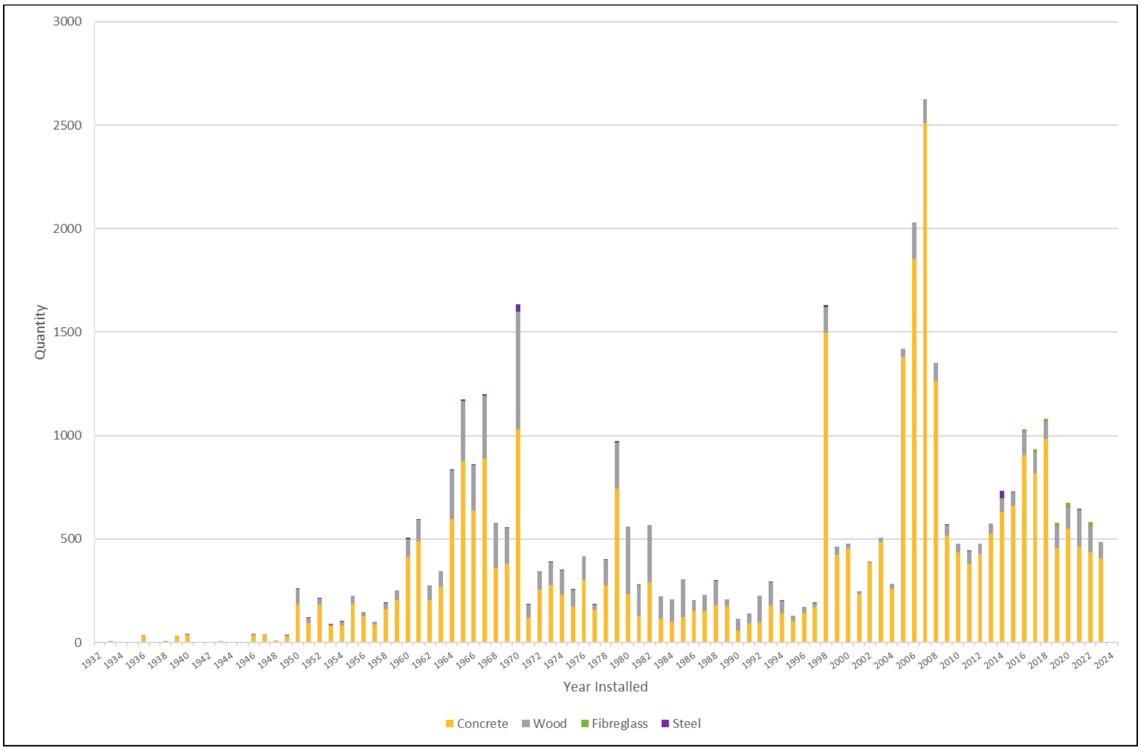


Figure 8-12 Age Profile of Poles

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

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

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

8.5.3.2 Subtransmission Lines

WELL's 56.8km of 33 kV subtransmission overhead lines are predominantly AAC conductors on both wood and concrete poles. The overhead line was used for subtransmission in the Hutt Valley and Porirua areas, converting to underground cable at the urban boundary. Subtransmission overhead lines are typically located on rural or sparsely developed land, although they are also in some other locations where difficult access would have made underground cable installation problematic. A summary and age profile of the subtransmission lines is shown in Figure 8-13.

Category	Quantity
33 kV Overhead Line	56.8km

Table 8-27 Summary of Subtransmission Lines

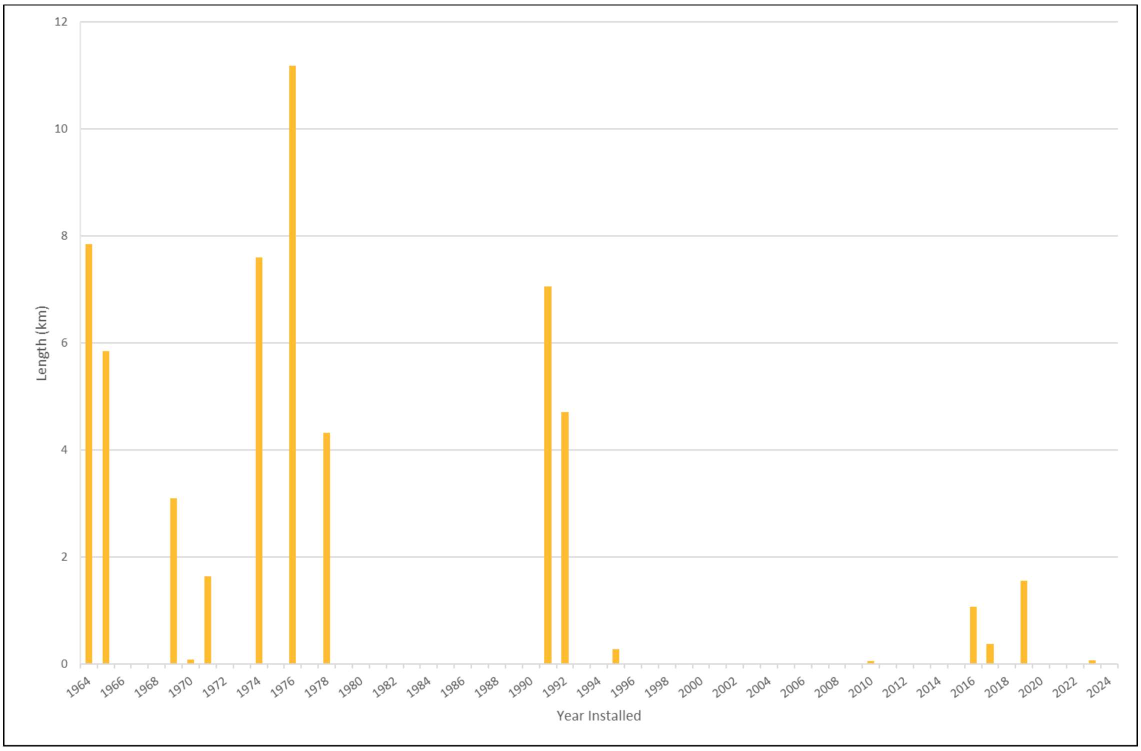


Figure 8-13 Age Profile of Subtransmission Line Conductors

8.5.3.3 Distribution and Low Voltage Conductors

Overhead conductors are predominantly aluminium conductor (AAC), with older lines being copper. In some areas aluminium conductor steel reinforced (ACSR) conductors have been used, with these having aluminised steel cores giving them greater corrosion resistance than standard ACSR with a galvanised steel core. New line reconstruction utilises all aluminium alloy conductor (AAAC). Small sections of covered conductor (CCT) have been used in locations with a history of outages due to windborne debris. Most low voltage conductors are PVC-covered, and low voltage aerial bundled conductor (LV ABC) have been used in a small number of tree encroachment areas, subject to District Plan allowances. Figure 8-14 shows the age profile of overhead line conductors.

Category	Quantity
11 kV Line	588.8 km
Low Voltage Line	1072.6 km
Streetlight Conductor	818.3 km

Table 8-28 Summary of Distribution Overhead Lines

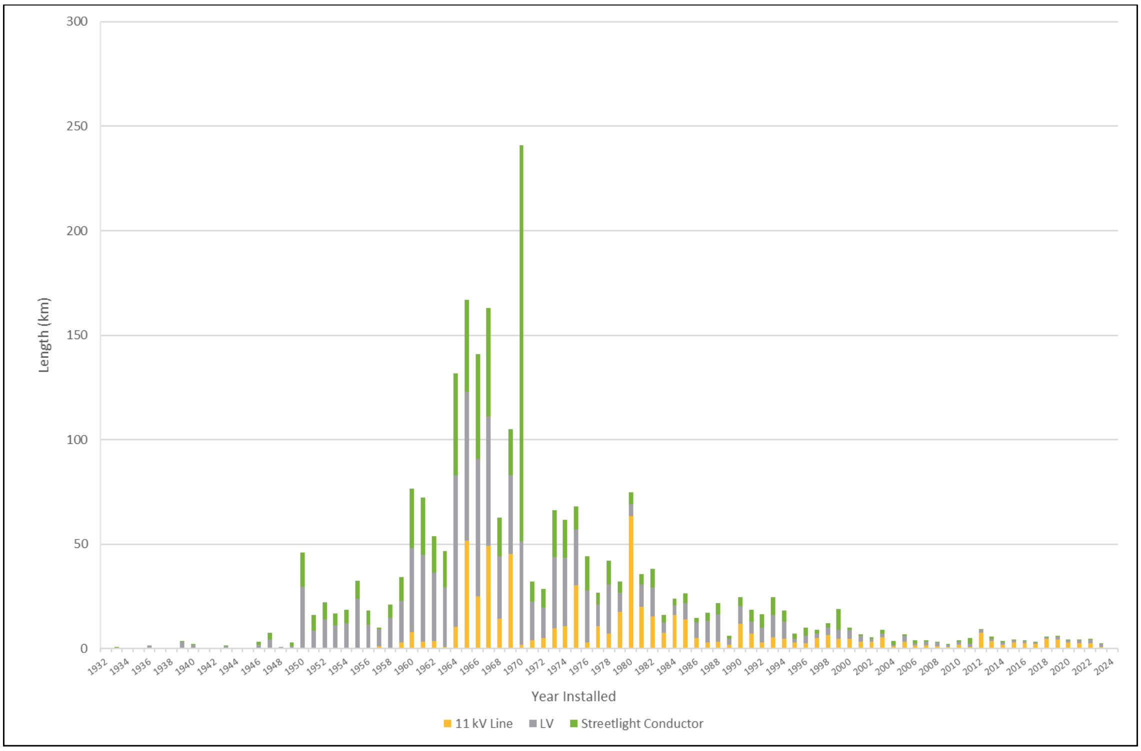


Figure 8-14 Age Profile of Distribution Overhead Line Conductors

Fleet Objectives

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

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

Table 8-29 Fleet-Specific Objectives for Pole and Overhead Line Fleets

Maintenance Activities

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

Activity	Description	Frequency
Inspection and condition assessment of 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, invasive inspection below groundline where Deuar testing cannot be completed, 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 the unit, assessment of condition and replacement of the on-board battery, and replacement onto the live line using a hot stick.	8 yearly

Table 8-30 Inspection and Routine Maintenance Schedule for Poles and Overhead Lines

All overhead lines are programmed for an annual visual inspection to determine any immediately obvious issues with the lines, the condition of components such as crossarms and insulators, and to note any prospective vegetation or safety issues. In addition, all connectors in the current carrying path get a thermal scan to identify any high-resistance joints which could potentially fail due to heating. These inspections drive a large part of the overhead corrective maintenance works and also contribute to asset replacement programmes for insulators and 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 visual-based criteria and historical failure rates. Assessment is moving to use a condition-based replacement profile based on a predictive model currently under development.

Pole Condition

WELL has been using the Deuar MPT40 to test its wooden pole population since 2011. The testing programme ensures the detection of structural issues along the length of the pole, including below ground level, and provides remaining life indicators and an assessment of the suitability of the pole to support the mechanical loading being applied to it. Approximately 1,800 poles are Deuar tested every year.

Approximately three-quarters of the poles installed in the Wellington area are concrete, which is durable and in good condition. The majority of the remainder are timber poles, which are tested and replaced in accordance with their Deuar serviceability index results or where there are visible structural defects.

Common condition issues with timber poles are deterioration of pole strength due to internal or external decay. Poles which are leaning, have head splits or incur third-party damage, may necessitate pole remediation or replacement.

Common condition issues with concrete poles include cracks, spalling (loss of concrete mass due to corrosion of the reinforcing steel), leaning poles and third-party damage.

A significant contributor to leaning poles on the Wellington network is third-party attachments. There are existing agreements to support telecommunications cables from Vodafone and Chorus on network poles. WELL has a standard that governs third-party attachments to network poles. This standard will ensure future connections to poles for telecommunications infrastructure meet WELL's requirements and do not have an injurious effect on the network or the safety of contractors and members of the public. Third-party network operators are required to contribute to the upgrade of network poles where there will be an adverse impact on pole service life or safe working load as the result of additional infrastructure connections.

Figure 8-15 shows the health-criticality matrix of WELL's fleet of poles. Pole asset health is determined by the pole's condition, while asset criticality is determined by the voltage of the lines connected to the pole and the number of customers that they supply.

		Lowest Impact		**Asset Criticality**			Highest Impact	
Asset Health		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0	3	-	-	1	-	-	-
	2.0	207	23	35	7	1	-	-
	3.0	10,193	1,322	1,473	466	2	2	-
	4.0	9,475	955	1,135	236	7	3	-
Best Health	5.0	10,237	1,279	1,691	437	8	-	-

Figure 8-15 Pole Health-Criticality Matrix

The forecast future condition of the pole fleet is modelled using survival curves. Figure 8-16 shows the survival curves for poles and crossarms. The survival curves for poles are derived from the age at which poles have been tagged. There is currently insufficient data to forecast the expected end of life for concrete poles. The survival curve for crossarms is based on the age at which a crossarm is identified as having a defect that requires the replacement of the arm.

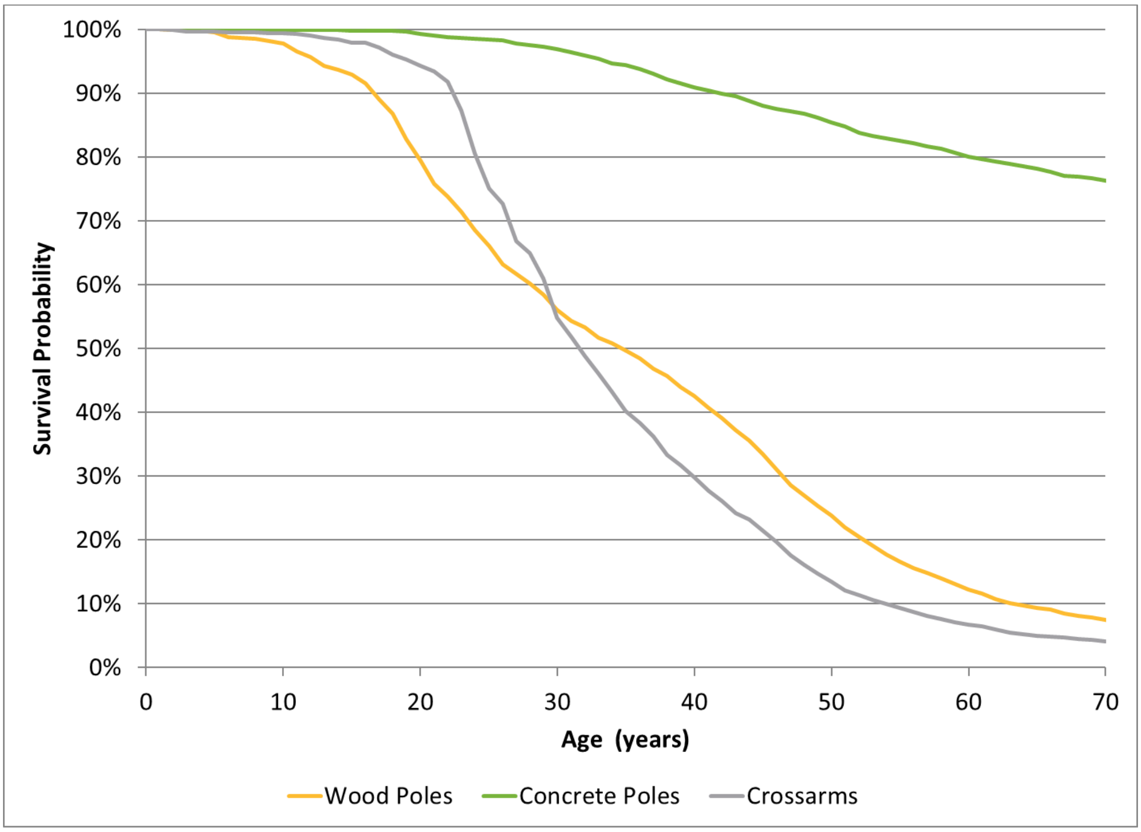


Figure 8-16 Pole and Crossarm Survival Curves

Overhead Line Condition

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

High wind loadings can sometimes result in fatigue failures around line hardware such as binders, compression sleeves, line guards and armour rods on the older AAC lines that have historically been used on the Wellington network. A number of Fargo sleeve-type automatic line splices have failed in service. These sleeves were only suitable for temporary repair. The failure mode for Fargo sleeves is likely to be vibration-related and can cause feeder faults when exposed to high vibrations. Fargo sleeves are no longer used on the network and are replaced with full-tension compression sleeves as they are found. Alternatively, the span will be re-conductored if the joints are not suitably located for replacement.

The forecast future condition of the overhead line conductor and connector fleet is modelled using failures per kilometre of conductor installed. Figure 8-17 shows the failure rates for conductors, jumpers, and connectors.

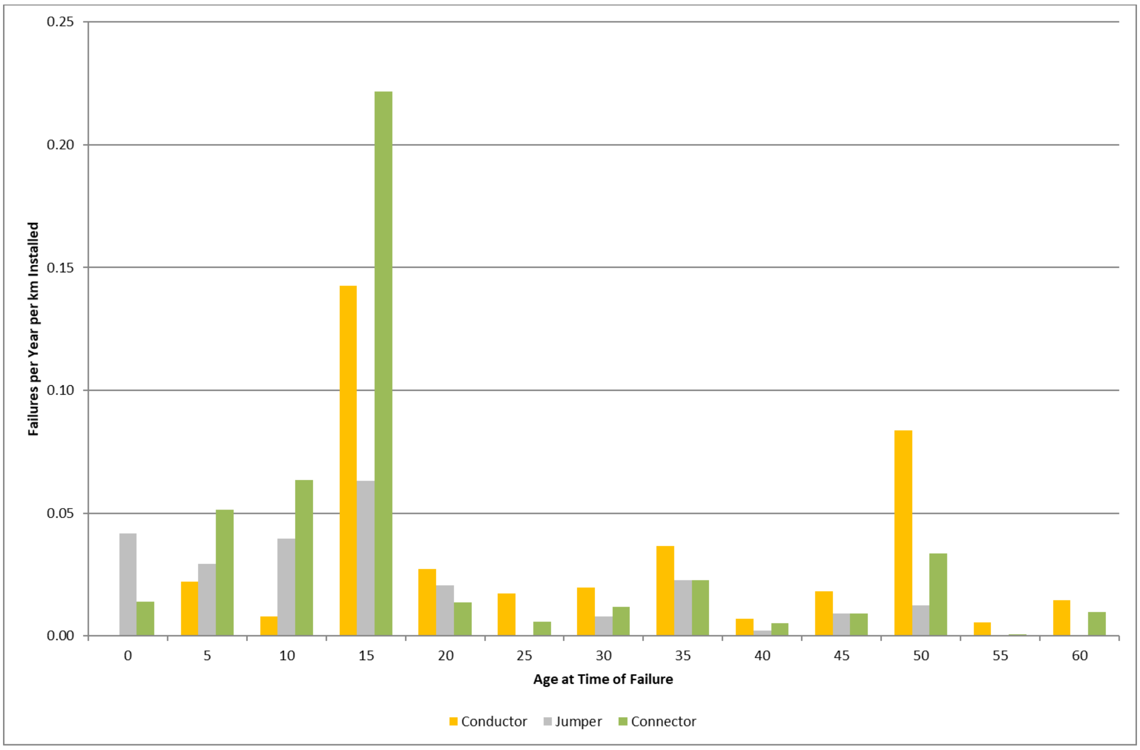


Figure 8-17 Overhead Conductor and Connector Failure Rate by Age

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

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 or have a major structural defect, and are programmed for replacement within three months. Yellow-tagged poles have a serviceability index of 0.5 to 1.0, or have moderate structural defects, and are programmed for replacement within 12 months. Blue tags are used to identify poles that have a reduced ability to support design loads but a serviceability index greater than 1.0, with these poles to have further engineering investigation within three months. For all pole tag colours, the climbing of tagged poles by contractors and third parties 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.

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

Renewal and Refurbishment – Lines

Since 2009, WELL has invested in the 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 reconductored, and have had all the line hardware, crossarms and poor condition poles replaced. These feeders have had a significant improvement in performance since this work was completed.

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

Significant projects for the renewal of overhead lines over the next 12 months are listed in Table 8-31.

Project	Description
Plimmerton Feeders	Further refurbishment stages of Plimmerton 8 and Plimmerton 11
Mana Feeders	Further Refurbishment stages of Mana 3
Wainuiomata Feeders	Refurbishment Wainuiomata 12

Table 8-31 Overhead Line Projects for 2024/25

Expenditure Summary for Overhead Lines

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Feeder Reliability Projects	875	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Pole Replacement Programme	6,232	6,340	6,358	6,235	6,165	5,990	5,903	5,518	5,535	5,413
Reactive Capital Expenditure	910	910	910	910	910	910	910	910	910	910
Capital Expenditure Total	**8,017**	**8,350**	**8,368**	**8,245**	**8,175**	**8,000**	**7,913**	**7,528**	**7,545**	**7,423**
Preventative Maintenance	685	679	672	673	676	678	676	670	665	659
Corrective Maintenance	996	996	996	996	996	996	996	996	996	996
Operational Expenditure Total	**1,681**	**1,675**	**1,668**	**1,669**	**1,672**	**1,674**	**1,672**	**1,666**	**1,661**	**1,655**

Table 8-32 Expenditure on Overhead Lines
($K in constant prices)

8.5.4 Distribution and LV Cables

Fleet Overview

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

Wellington CBD is operated in a closed 11 kV primary ring configuration, with short radial feeders interconnecting neighbouring rings or zone substations. This part of the network uses automatically operating circuit breakers, with differential protection on cables between distribution substations, rather than manually operated ring main switches between switching zones. This results in higher reliability as smaller sections of the 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 customers can be switched to neighbouring feeders.

Category	Quantity
11 kV cable (incl. risers)	1,218 km
Low Voltage cable (incl. risers)	1,787 km
Streetlight cable	1,149 km

Table 8-33 Summary of Distribution Cables

Approximately 85% of the underground 11 kV cables are PILC and PIAS and the remaining 15% are XLPE insulated cables, installed from 2000 onwards. 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 8-18.

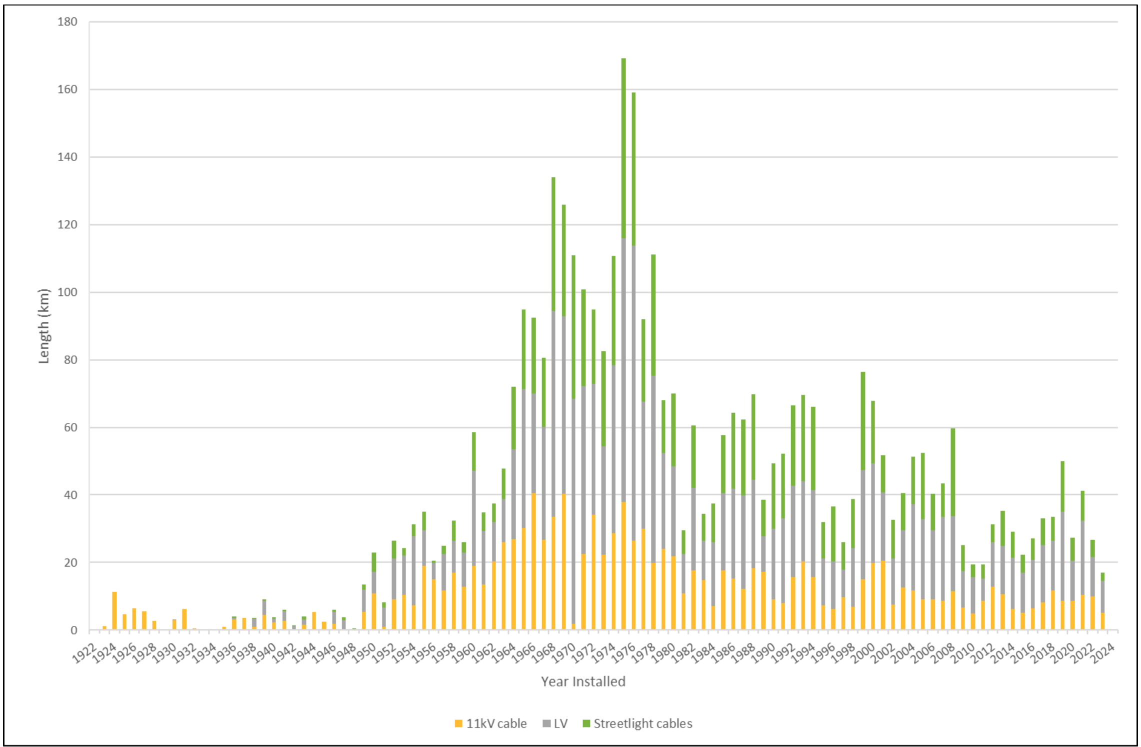


Figure 8-18 Age Profile of Distribution Cables

Fleet Objectives

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

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

Table 8-34 Fleet-Specific Objectives for Distribution Cable Fleets

Maintenance Activities

Maintenance of the underground distribution cable network is limited to visual inspection and thermal imaging of cable terminations. WELL has been trialling cable testing technology by testing poor-performing cables with a variety of diagnostic tools. The purpose of this trial is to gain a sufficient understanding of the results produced by these tools and match them to actual cable performance to provide confidence in their suitability as a condition assessment tool to:

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

Distribution Cable Condition

Underground cables usually have a long life and high reliability as they are not subjected to environmental hazards however, as these cables age, performance is seen to decrease. External influences such as third-party strikes, inadvertent overloading, or even rapid increases in load within normal ratings can reduce the service life of a cable. Some instances of failure are due to workmanship on newer joints and terminations (which can be addressed through training and education), whilst others are due to age, environment or external strikes. Figure 8-19 shows the health criticality matrix for WELL's fleet of 11kV cable, by cable length.

		Lowest Impact		**Asset Criticality**			Highest Impact	
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0	-	-	-	-	0.3	-	-
Asset Health	2.0	2.1	8.4	21.1	4.6	31.0	24.4	-
	3.0	44.1	136.4	306.5	74.3	73.0	59.2	-
	4.0	41.0	55.6	110.9	34.5	45.8	18.3	-
Best Health	5.0	16.6	15.9	51.9	15.0	14.1	5.4	-

Figure 8-19 11 kV Cable Health-Criticality Matrix (km)

The forecast future condition of the distribution cable fleet is modelled using failures per km installed, with a cable unit being defined as the network average segment length of 150m, to allow a direct comparison between the failure rates of cables and their accessories. Figure 8-20 shows the failure rates for cables, joints, and terminations.

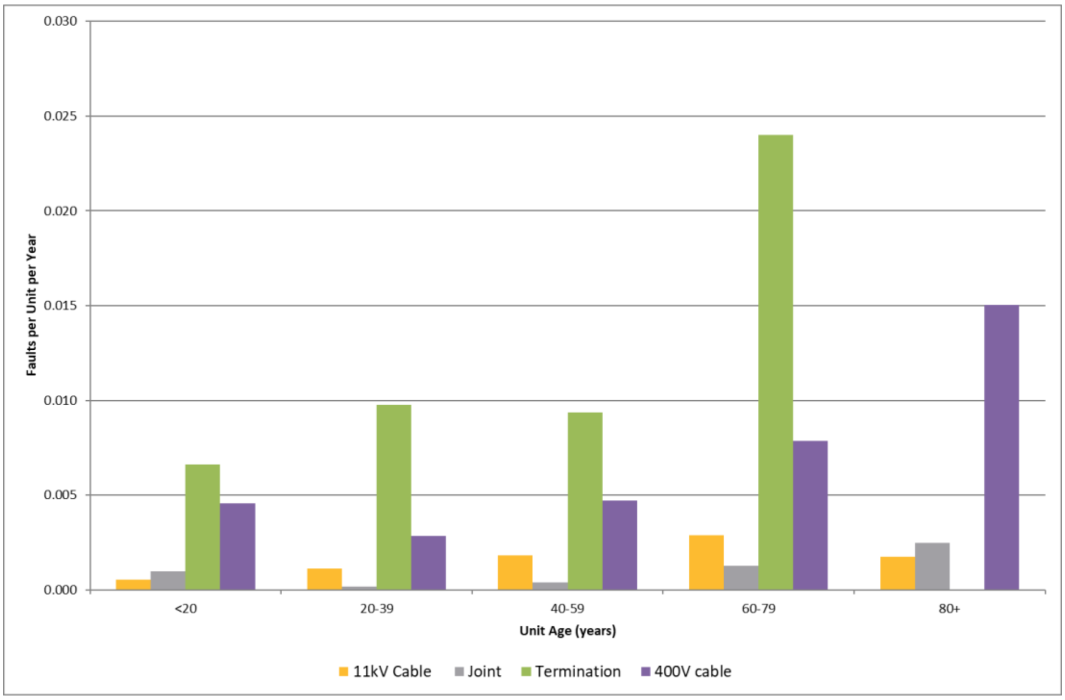


Figure 8-20 Cable Failure Rate by Age

The failure rate data indicates that outdoor terminations are the weakest component of the 11 kV cable system, with a higher rate of failure at all ages, and a significant increase in failures beyond 60 years old.

Applying the average failure rates to the fleet, combined with an estimate of the customer impact of each potential failure, produces a forecast of the underlying trend in future performance due to cable conditions without intervention, which is presented in Figure 8-21. The actions to control this trend and maintain performance at current levels are described in the following section on Renewal and Refurbishment.

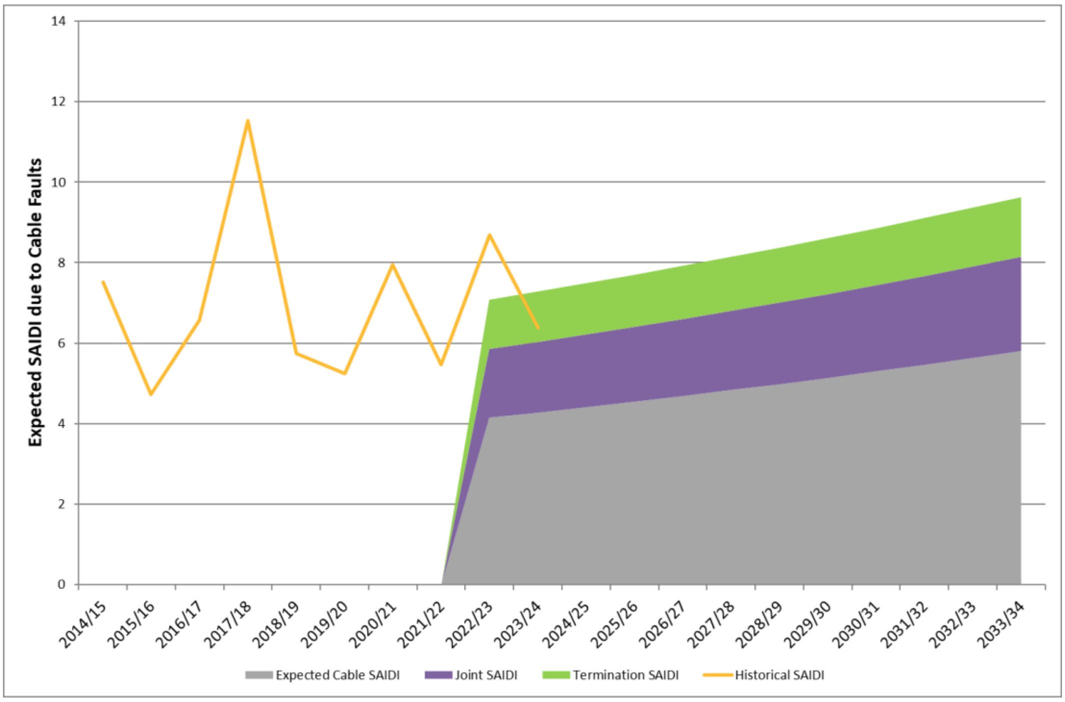


Figure 8-21 Forecast 11kV Cable Fleet Performance Trend without Intervention

Renewal and Refurbishment

The volume of cable in service and the high unit cost of replacement make the underground cable network a significant risk for WELL. Allowing the fleets to run to failure would result in a gradual reduction in quality of supply as shown in Figure 8-21, whereas proactive replacement carries significant financial cost without being guaranteed to mitigate the risk of deteriorating performance. WELL has adopted a strategy for managing its cable fleets that seeks to minimise the impact on customers, in terms of both quality of supply, and cost.

The cable fleet strategy, set out below, targets specific areas of the forecast future performance in order to maintain the reliability of the fleet at current levels.

- Cable terminations represent low-hanging fruit due to their accessibility. A programme of condition assessment will identify deteriorating cable terminations, allowing them to be replaced before they fail;
- Investment in modern cable diagnostics equipment will improve the understanding of cable condition, and allow targeted replacement of the cable sections posing the greatest risk to the quality of supply;
- Increasing the number of circuit breakers and remote-controlled switches on the underground network will reduce the impact of each cable fault (see Section 8.5.8.3);

- The early failure of cable fittings, particularly those younger than 20 years, is being controlled through training and monitoring requirements for cable jointer competency, and close cooperation with cable fitting suppliers to investigate and understand the causes of any failures; and
- Cable fitting technology will continue being reviewed, to ensure the joints and terminations approved for use on the network are suitable for Wellington conditions.

WELL will eventually need to commence a large programme of distribution cable renewals. WELL's preferred approach is to use the strategies listed above to manage the customer impact of the distribution cable fleet for the period of this AMP, delaying the commencement of that programme. The purpose of this is to avoid superimposing distribution cable renewal costs onto the significant network reinforcement costs being driven by decarbonisation load growth as discussed in Section 4. The performance of the cable fleet will continue to be closely monitored to ensure that this approach remains viable and is delivering the best outcomes for the long-term benefit of customers.

Significant projects for the renewal of distribution cables over the next 12 months are listed in Table 8-35.

Project	Description
University 13	Complete the 11kV cable bypass of Mount Street Cemetery.

Table 8-35 Distribution Cable Projects for 2024/25

Expenditure Summary for Distribution and LV Cable

Table 8-36 details the expected expenditure on distribution and LV cable by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Asset Replacement and Renewal CAPEX	499	528	528	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Reactive Capital Expenditure	2,206	2,206	2,206	2,206	2,206	2,206	2,206	2,206	2,206	2,206
Capital Expenditure Total	**2,705**	**2,734**	**2,734**	**3,206**	**3,206**	**3,206**	**3,206**	**3,206**	**3,206**	**3,206**
Corrective Maintenance	101	101	101	101	101	101	101	101	101	101
Operational Expenditure Total	**101**	**101**	**101**	**101**	**101**	**101**	**101**	**101**	**101**	**101**

Table 8-36 Expenditure on Distribution and LV Cable
($K in constant prices)

8.5.5 Distribution Substations

8.5.5.1 Distribution Transformers

Fleet Overview

Of the distribution transformer population, 60% are ground-mounted and 40% 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 2,000 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 on the coast, a transformer may not reach this age due to corrosion. The age profile of distribution transformers is shown in Figure 8-22.

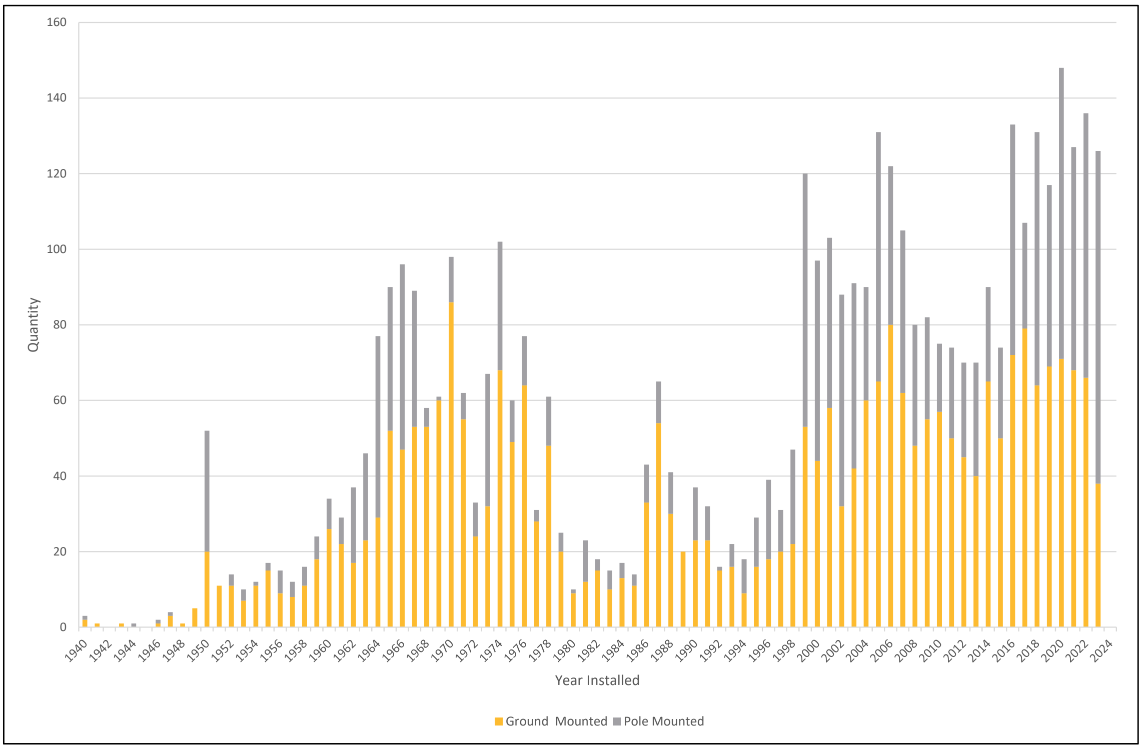


Figure 8-22 Age Profile of Distribution Transformers

In addition to pole and integral pad mount berm substations, WELL owns 529 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 8-37.

Category	Quantity
Distribution transformers	4,546
Distribution transformers – Total	**4,546**
WELL owned substations	3,938
Customer-owned substations containing WELL owned equipment	668
Distribution substations – Total	**4,606**

Table 8-37 Summary of Distribution Transformers and Substations

Fleet Objectives

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

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

Table 8-38 Fleet-Specific Objectives for Distribution Transformers and Substations

Maintenance Activities

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

Activity	Description	Frequency
Inspection of Distribution Substations	Routine inspection of distribution substations to ensure asset integrity, security and safety. Record and report defects, and 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 on 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 on visible defects. Thermal image of accessible connections.	Annual
Transformer oil test	Dissolved gas analysis of transformers 1000kVA and larger.	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 8-39 Inspection and Routine Maintenance Schedule for Distribution Transformers

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

Internal Bushing Transformers

Ground-mounted transformers manufactured by Bonar Long, Bryce and ASEA were installed between 1946 and 1999. 34 of these transformers have internal 11 kV bushings, with cambric cables being terminated inside the transformer tank. This does not pose a problem during normal operation, however, if the switchgear at the site requires replacement, then the cables and hence the transformer will also need to be replaced.

Distribution Transformer Condition

Figure 8-23 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 customers connected to the transformer.

		Lowest Impact		Asset Criticality				Highest Impact
		5.0	4.0	3.0	2.5	2.0	1.5	1.0
Worst Health	1.0							
Asset Health	2.0	6	8	13	2	4		
	3.0	401	597	952	234	329	102	
	4.0	206	355	731	172	109	62	
Best Health	5.0	43	66	116	16	14	8	

Figure 8-23 Distribution Transformer Health-Criticality Matrix

The forecast future condition of the distribution transformer fleet is modelled using survival curves. Figure 8-24 shows the survival curves for ground and pole-mounted distribution transformers. Ground-mounted transformers are further divided into those located indoors (including berm substations), and those located outdoors.

These survival curves are based on the age at which a transformer is identified as having a defect that is best resolved through transformer replacement. Notable from these curves is the significant additional life gained by housing transformers under cover (representing 54% of WELL's distribution transformer fleet), and the similarity between pole-mounted and outdoor ground-mounted transformers, with the earlier onset for replacement of pole-mounted transformers reflecting their greater exposure to lightning and their lower accessibility for repairs.

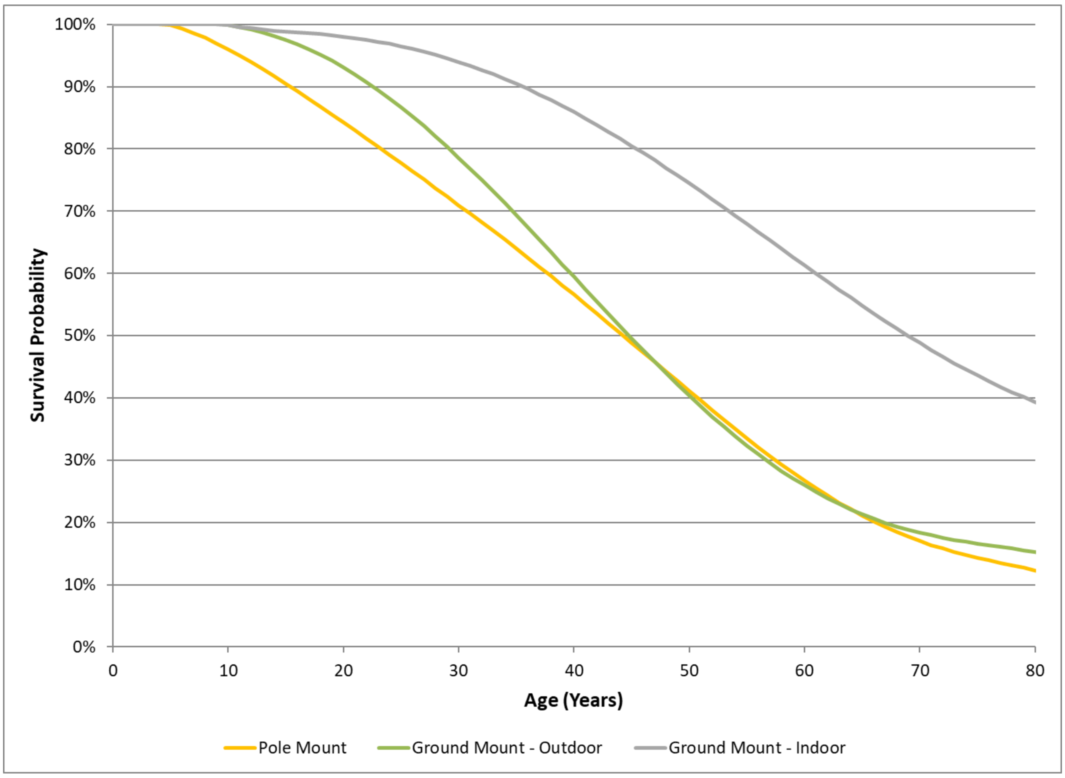


Figure 8-24 Distribution Transformer Survival Curves

Renewal and Refurbishment

If a distribution transformer is found to be in an unsatisfactory condition during its regular inspection, it is programmed for corrective maintenance or replacement. In-service transformer failures are investigated to determine the cause. This assessment determines if the unit is to be repaired, refurbished, or scrapped depending on the cost and residual life of the unit. Typical condition issues include rust, heavy insulating fluid leaks, and integrity and security of the unit. 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 integral substation units 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 was installed, however, it was found that the reduced civil cost was offset by the additional cost of 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 8-40 details the expected expenditure on distribution substations by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Seismic Strengthening	725	460	650	-	-	-	-	-	-	
Asset Replacement and Renewal CAPEX	3,516	3,347	3,347	3,567	3,292	3,100	3,100	3,375	3,459	3,899
Reactive Capital Expenditure	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970
Capital Expenditure Total	**6,211**	**5,777**	**5,967**	**5,537**	**5,262**	**5,070**	**5,070**	**5,345**	**5,429**	**5,869**
Preventative Maintenance	768	768	768	768	768	768	768	768	768	768
Corrective Maintenance	760	760	760	760	760	760	760	760	760	760
Operational Expenditure Total	**1,528**	**1,528**	**1,528**	**1,528**	**1,528**	**1,528**	**1,528**	**1,528**	**1,528**	**1,528**

Table 8-40 Expenditure on Distribution Substations ($K in constant prices)

8.5.6 Ground Mounted Distribution Switchgear

Fleet Overview

This section covers ring main units (RMUs) and switching equipment that is often installed outdoors. It does not include zone substation circuit breakers, which are discussed in Section 8.5.2. There are 1,230 distribution circuit breakers and 2,345 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 750 kVA and above. Other ground-mounted switches include fuse switches for the protection of distribution transformers, and load break switches to allow isolation and reconfiguration of components on the network, often with multiple switches combined in a single ring main unit.

The age profiles of distribution circuit breakers and ground-mounted switchgear are shown in Figure 8-25 and Figure 8-26.

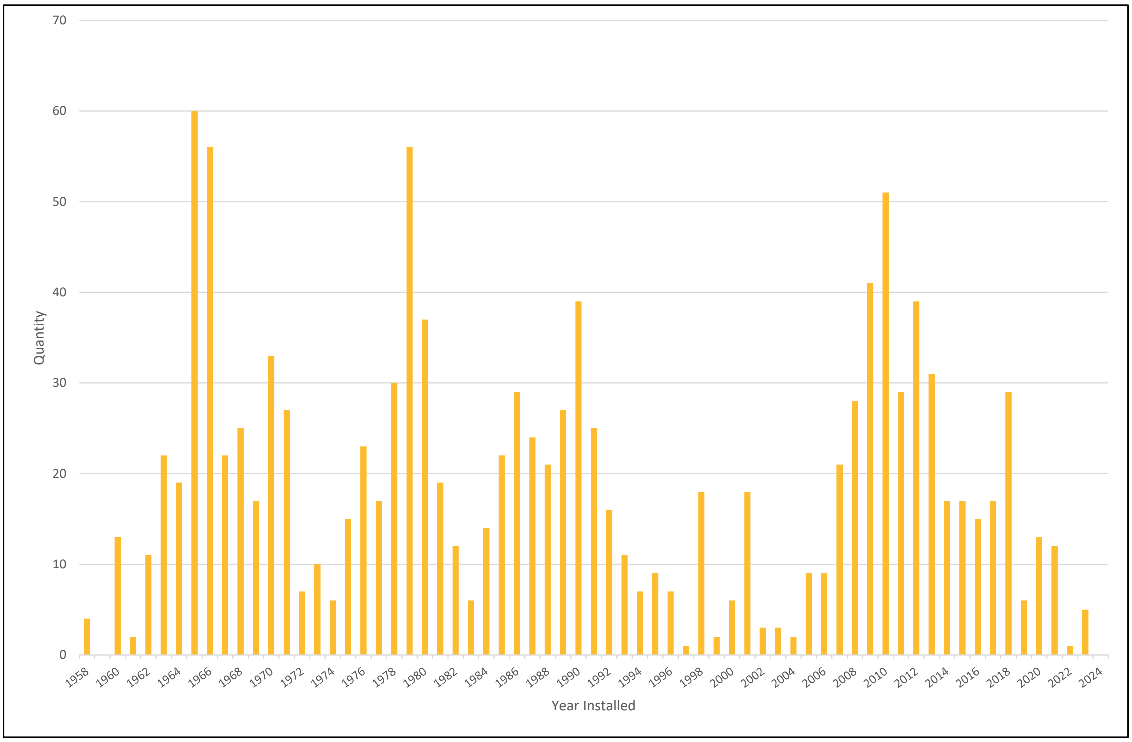


Figure 8-25 Age Profile for Distribution Circuit Breakers

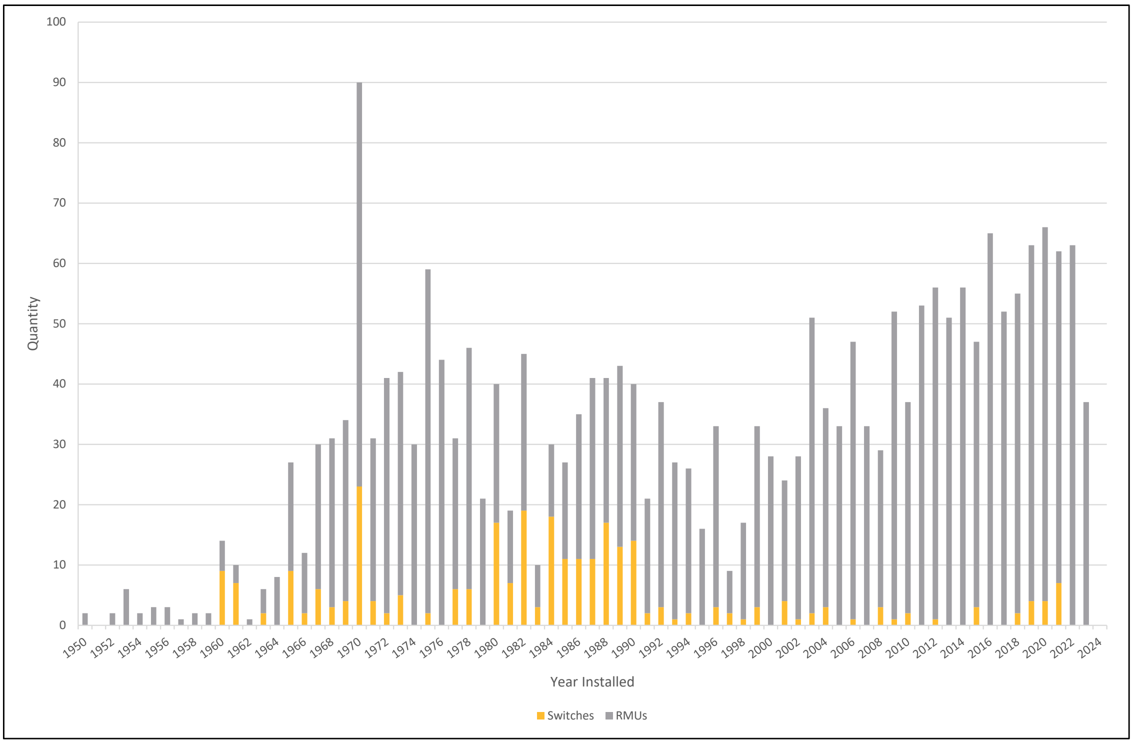


Figure 8-26 Age Profile of Other Ground-Mounted Distribution Switchgear

The average age of distribution circuit breakers in the network is around 34 years, while the average age of ring main units is 27 years. A summary of circuit breakers and ground-mounted distribution switchgear, of both stand-alone and ring main unit types, is shown in Table 8-41 and Table 8-42.

Category	Quantity
Distribution Circuit Breakers	1,230
Oil Insulated Switches	256
Oil Insulated RMUs	147
SF_6 Insulated Switches	13
SF_6 Insulated RMUs	961
Resin Insulated Switches	17
Resin Insulated RMUs	951

Table 8-41 Summary of Ground-Mounted Distribution Switchgear

Manufacturer	Breaker Type	Quantity
ABB	SF_6	27
AEI	Oil	47
BTH	Oil	52
Entec	Vacuum	25
GEC/Alstom	Oil	49
Hawker Siddeley	Vacuum	21
Merlin Gerin / Schneider	SF_6	294
Reyrolle	Oil	598
	Vacuum	65
South Wales	SF_6	36
Statter	Oil	16[29]
Total		**1,230**

Table 8-42 Summary of Distribution Circuit Breakers by Manufacturer

Fleet Objectives

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

Priority Area	Objective
Safety and Environment	No injuries resulting from working on and around distribution switchgear. Minimise the loss of SF_6 to the environment.
Network Performance	Distribution switchgear to be safe to operate live, to minimise customer impact during switching.

Table 8-43 Fleet-Specific Objectives for Ground-Mounted Distribution Switchgear

Maintenance Activities

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

[29] 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 on visible defects. Thermal image of accessible connections. Handheld PD and Ultrasonic scan.	Annually
Switchgear Maintenance (Magnefix)	Clean and maintain the Magnefix unit, inspect and replace link caps as required, test fuses, and check terminations where possible.	Triggered by Inspection Results
Circuit Breaker Maintenance (Oil CB)	Withdraw and drain OCB, ensure correct mechanical operation, dress or replace contacts as required, undertake minor repairs, refill with clean oil, and return to service. Trip timing test before and after service	5 yearly
Switch Maintenance (Oil Switch)	Clean and maintain the oil switch unit, drain the oil check internally, and check terminations and cable compartments. Ensure correct operation of the unit. Refill with clean oil.	5 yearly
Circuit Breaker Maintenance (Vacuum or Gas CB)	Withdraw CB and maintain carriage and mechanisms as required, record the condition of interrupter bottles where possible, and 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 the unit. Check gas/vacuum levels.	Triggered by Inspection Results
11 kV Switchboard Major Maintenance	Full or bus section shutdown, removal of all busbar and chamber access panels, cleaning and inspecting all switchboard fixed portion components, and undertaking condition and diagnostic tests as required. Maintain VTs and CTs. Return to service	10 yearly

Table 8-44 Inspection and Routine Maintenance Schedule for Distribution Switchgear

<u>Distribution Switchgear Condition</u>

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 8-27 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							
	1.5	15	36	109	23	1		
	2.0			1				
Asset Health	2.5	88	199	359	160	236	99	
	3.0	109	178	538	162	404	146	
	4.0	49	66	265	66	103	41	
Best Health	5.0	9	22	55	11	12	6	

Figure 8-27 Distribution Switchgear Health-Criticality Matrix

Specific condition issues for distribution switchgear are:

Schneider Ringmaster

A number of gas depressurisation events have occurred on Schneider Ringmaster switchgear, with the first recorded loss of gas occurring in 2011 after about 10 years in service. These have been identified as only affecting Ringmaster RMUs and not circuit breakers. The affected RMUs were manufactured between 2000 and 2005, and 90 of these units are currently in service. A loss of gas does not cause the electrical failure of the unit, however, depressurised units are placed under operational restrictions until their replacement, so that they cannot be operated live. The cautious monitoring of the gas levels before operating the RMUs has been reinforced to switching staff.

The manufacturer has identified that the most likely cause of failure is stress fractures in the resin gas tank moulding due to temperature cycling, combined with a higher gas pressure being used for RMUs manufactured over the affected period. The failure is not believed to be related to the design of the switchgear, and the switchgear remains approved for installation on the network.

Solid Insulation Magnefix

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

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

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

Long and Crawford

One Long and Crawford ring main unit remains in service on the network. The replacement of this unit is on hold pending the customer's decision on their future power supply requirements.

Statter

As of October 2023, there are 36 sites with Statter switchgear, with 88 units in service including circuit breakers, oil switches, and fuse switches, installed between 1960 and 1990.

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 controls 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 customers. These will be replaced with modular secondary-class circuit breakers to maintain reliability levels. There is an ongoing programme for the replacement of Statter switchgear which is planned for completion in the 2027 calendar year.

Renewal and Refurbishment

HV Distribution Switchgear (Ground Mounted)

As noted above, this section excludes zone substation circuit breakers, which are discussed in Section 8.5.2.2.

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 the 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.

In rare cases, when any switchgear device fails, the reason for the failure is studied and a cost-benefit analysis is 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 switches with identified issues around age, condition and known operational issues. These are being replaced based on the risk assessment for that type.

Oil-insulated switchgear is no longer installed, with vacuum or gas (SF_6) insulated types now being used. WELL intends to phase out the use of SF_6 for new distribution switchgear due to that gas' potential contribution to climate change, however, there are currently no SF_6-free units on the New Zealand market that meet WELL's requirements, particularly around physical dimensions and arc fault containment.

Significant projects for the renewal of ground-mounted switchgear over the next 12 months are listed in Table 8-45.

Project	Description
Porirua CBD Statters	Completion of the replacement of Statter switchgear at four substations in the Porirua CBD
Normandale Bridge	Replacement of oil switchgear in this Normandale substation
Esplanade E	Replacement of oil switchgear in this Petone substation

Table 8-45 Ground Mounted Switchgear Projects for 2024/25

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

Generator Connection Switchgear

WELL uses temporary diesel generation to support planned outages where it is cost-effective to do so. To support this activity, WELL intends to procure portable 11 kV switchgear that is designed to facilitate the connection of temporary generation to the 11 kV network.

Expenditure Summary for Ground-mounted Switchgear

Table 8-46 details the expected expenditure on ground-mounted switchgear by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Statter Replacement Programme	2,991	4,805	3,478	1,858	-	-	-	-	-	-
Partial Discharge Mitigation	300	300	300	300	300	300	300	300	300	300
Other Asset Replacement and Renewal CAPEX	703	2,242	4,021	2,430	4,033	4,000	4,024	4,027	4,078	3,945
Generator Connection Switchgear	-	2,000	-	-	-	-	-	-	-	-
Reactive Capital Expenditure	410	410	410	410	410	410	410	410	410	410
Capital Expenditure Total	**4,404**	**9,757**	**8,209**	**4,998**	**4,743**	**4,710**	**4,734**	**4,737**	**4,788**	**4,655**
Preventative Maintenance	665	710	831	926	852	966	689	782	860	720
Corrective Maintenance	420	420	420	420	420	420	420	420	420	420
Operational Expenditure Total	**1,085**	**1,130**	**1,251**	**1,346**	**1,272**	**1,386**	**1,109**	**1,202**	**1,280**	**1,140**

Table 8-46 Expenditure on Ground-mounted Switchgear
($K in constant prices)

8.5.6.1 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 22,502 LV units (link pillars, pits, cabinets, under veranda boxes, 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 provide the ability to sectionalise large LV circuits. A high-level breakdown of types is listed in Table 8-47.

Type	Quantity
Customer service pillar	16,919
Customer service pit	3,907
Link pillars, pits and cabinets	1,676
Total	**22,502**

Table 8-47 Summary of LV Units

An age profile of LV Units (pillars, pits, cabinets and boards) is shown in Figure 8-28.[30]

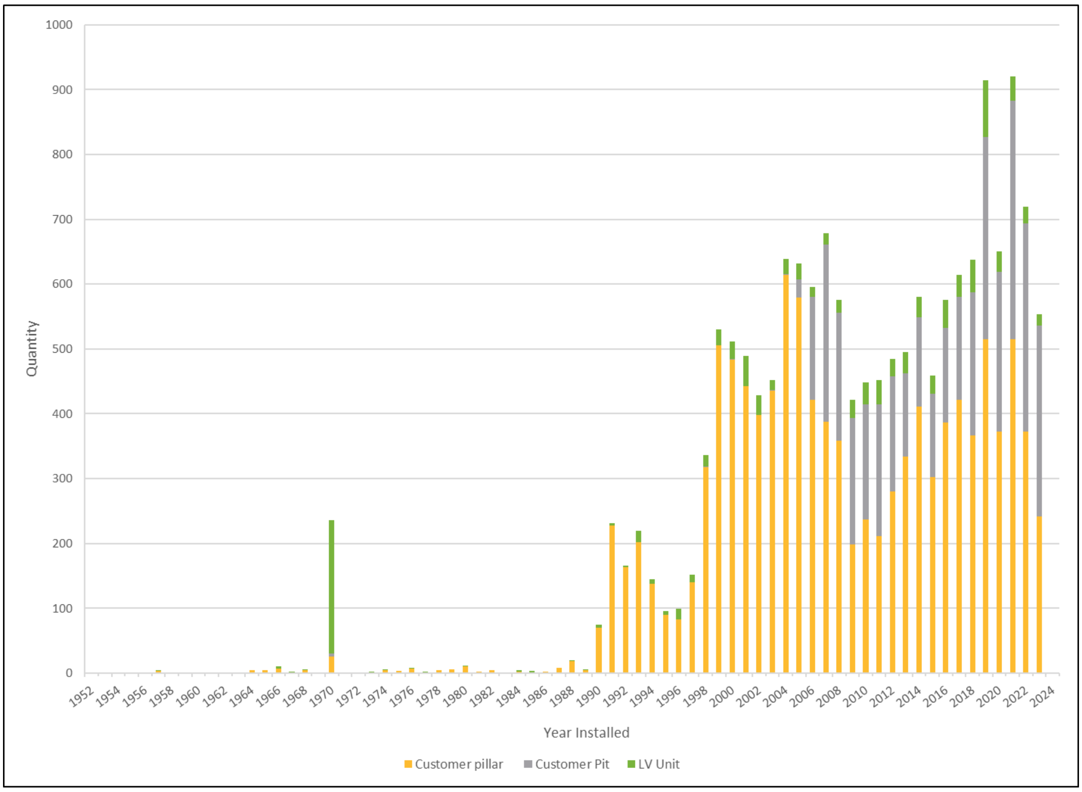


Figure 8-28 Age Profile of Pillars, Pillars and Cabinets

[30] There are 4,792 low voltage pillars, pits, cabinets and LV boards that have unknown installation dates and these have not been included in the age profile.

Fleet Objectives

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

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

Table 8-48 Fleet-Specific Objectives for Low Voltage Equipment

Maintenance Activities

The following routine planned inspection and maintenance activities are undertaken on low voltage pits and pillars, for either customer 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 the 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 8-49 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 8-50 details the expected expenditure on low voltage pits and pillars by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Asset Replacement and Renewal CAPEX	150	150	150	150	150	150	150	150	150	150
Reactive Capital Expenditure	1,506	1,506	1,506	1,506	1,506	1,506	1,506	1,506	1,506	1,506
Capital Expenditure Total	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**	**1,656**
Preventative Maintenance	244	244	244	244	244	244	244	244	244	244
Corrective Maintenance	146	146	146	146	146	146	146	146	146	146
Operational Expenditure Total	**390**	**390**	**390**	**390**	**390**	**390**	**390**	**390**	**390**	**390**

Table 8-50 Expenditure on Low Voltage Pits and Pillars
($K in constant prices)

8.5.7 Pole-mounted Distribution Switchgear

8.5.7.1 Reclosers and Gas Switches

Fleet Overview

Automatic circuit reclosers are pole-mounted circuit breakers that protect the rural 11 kV overhead network. The majority of the 18 reclosers on the network are vacuum models with electronic controllers, with only one being an older hydraulic type. The individual types of auto-reclosers are shown in Table 8-51.

Manufacturer	Insulation	Model	Quantity
G&W	Solid/Vacuum	Viper-S	17
Reyrolle	Oil	OYT	1
Total			**18**

Table 8-51 Summary of Recloser Types

The age profile of WELL's reclosers is shown in Figure 8-29.

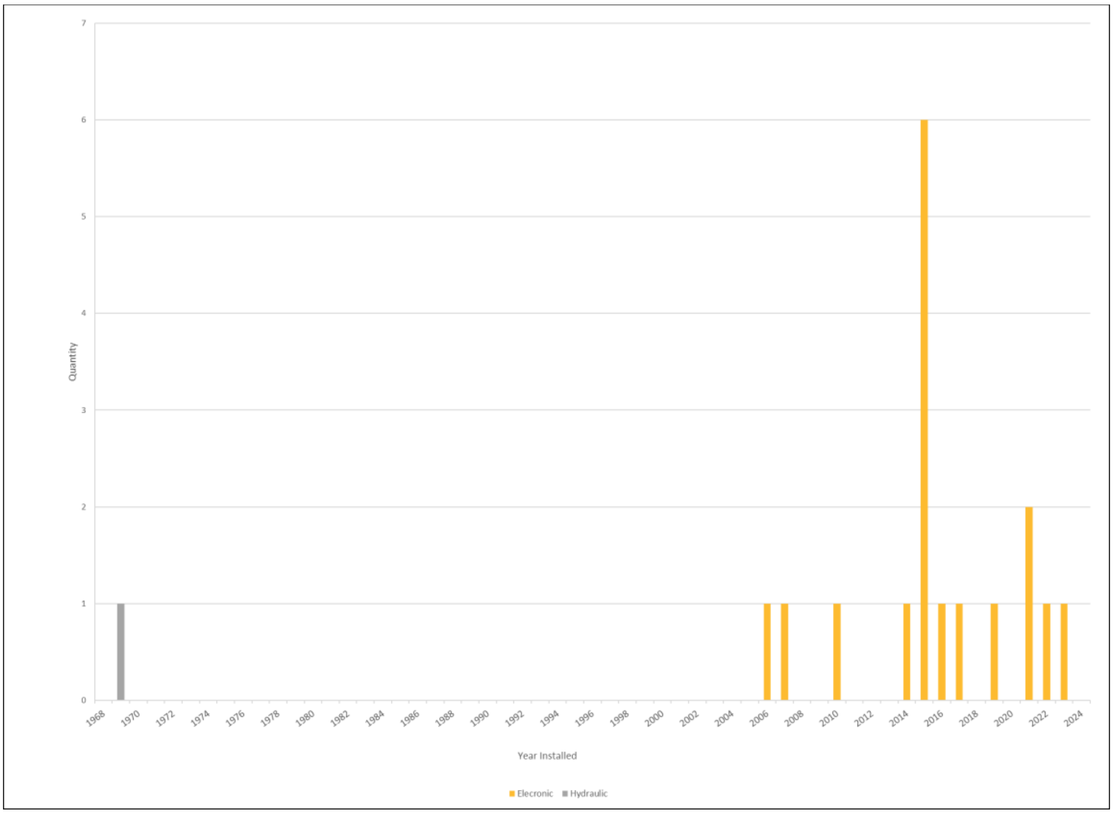


Figure 8-29 Age Profile of Reclosers

Fleet Objectives

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

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

Table 8-52 Fleet-Specific Objectives for Reclosers

Maintenance Activities

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

Activity	Description	Frequency
Visual Inspection and Thermal Image	Visual inspection of equipment and condition assessment based on visible defects. Thermal image of accessible connections.	Annually
Recloser Operational Check	Bypass unit or back feed, arrange remote and local operation in conjunction with NCR to ensure correct operation and indication.	Annually
Recloser Service	Maintenance of hydraulic recloser, inspecting and maintaining contacts, changing oil as required, prove correct operation.	3 yearly
Inspection and Testing of Batteries	Routine visual inspection of batteries, chargers and associated equipment inside the electronic recloser control panel. Discharge test of batteries to confirm health	1 yearly
Inspection and Testing of Earthing	Visual inspection of earthing system installation and mechanical protection, testing of individual and combined earth bank resistance.	5 yearly

Table 8-53 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 modern vacuum types, in good condition, and performing as expected. After the replacement of the last hydraulic recloser, planned for early 2024, no further renewal is expected to be required within the AMP planning period.

Expenditure Summary for Reclosers

Table 8-54 details the expected expenditure on reclosers by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Asset Replacement and Renewal CAPEX	-	-	-	-	-	-	-	-	-	-
Feeder Reliability Projects	1,550	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Capital Expenditure Total	**1,550**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**
Preventative Maintenance	11	12	12	13	14	15	15	15	15	15
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**21**	**22**	**22**	**23**	**24**	**25**	**25**	**25**	**25**	**25**

Table 8-54 Expenditure on Reclosers
($K in constant prices)

8.5.7.2 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 8-55.

Category	Quantity
Gas Switches	70
Air Break Switches	303
Knife Links	31
Dropout Fuses	2,205
Dropout Sectionalisers	16
Total	**2,625**

Table 8-55 Summary of Pole-Mounted Distribution Switchgear

The age profiles of these devices are shown in Figure 8-30.

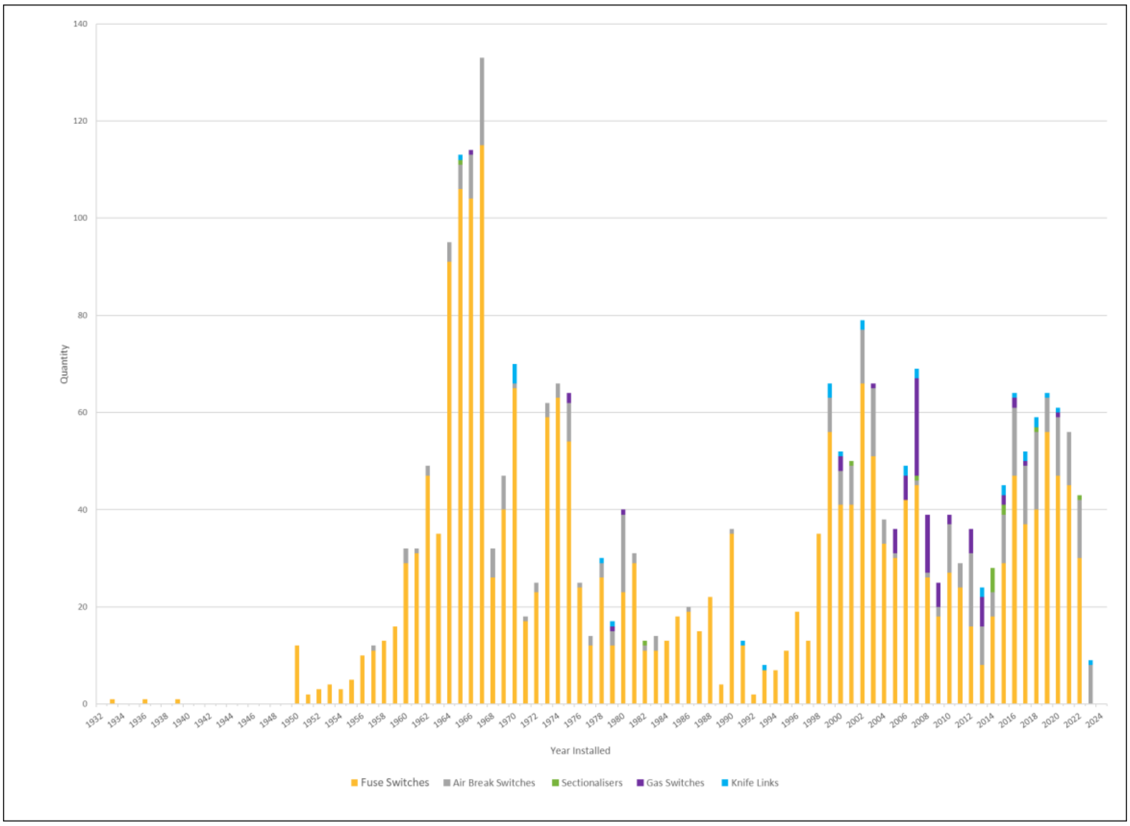


Figure 8-30 Age Profile of Overhead Switchgear and Devices

Fleet Objectives

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

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

Table 8-56 Fleet-Specific Objectives for Pole-Mounted Switchgear

Maintenance Activities

The following routine planned inspection, testing and maintenance activities that are undertaken on overhead switches, links and fuses are shown in Table 8-57.

Activity	Description	Frequency
Visual Inspection and Thermal Image	Visual inspection of equipment and condition assessment based on visible defects. Thermal image of accessible connections.	Annually
ABS Service	Maintained air break switch, clean and adjust contacts, and check correct operation.	3 yearly
HV Knife Link Service	Maintain knife links, clean and adjust contacts, and 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 8-57 Inspection and Routine Maintenance Schedule for Overhead Switch Equipment

All overhead switches and links are treated in the same manner and are maintained under the preventative maintenance programme detailed above. Overhead HV fuses are visually inspected during the annual overhead line survey. The large quantity and low risk associated with fuses do not justify an independent inspection and maintenance programme.

Condition of Overhead Switches, Links and Fuses

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

The coastal environment around Wellington causes accelerated corrosion on galvanised overhead equipment components and, where possible, stainless steel fittings are used as they have proven to provide a longer and more cost-effective solution.

The forecast future condition of the overhead switch fleet is modelled using survival curves, shown in Figure 8-31. The survival curve is based on the age at which switches have been replaced.

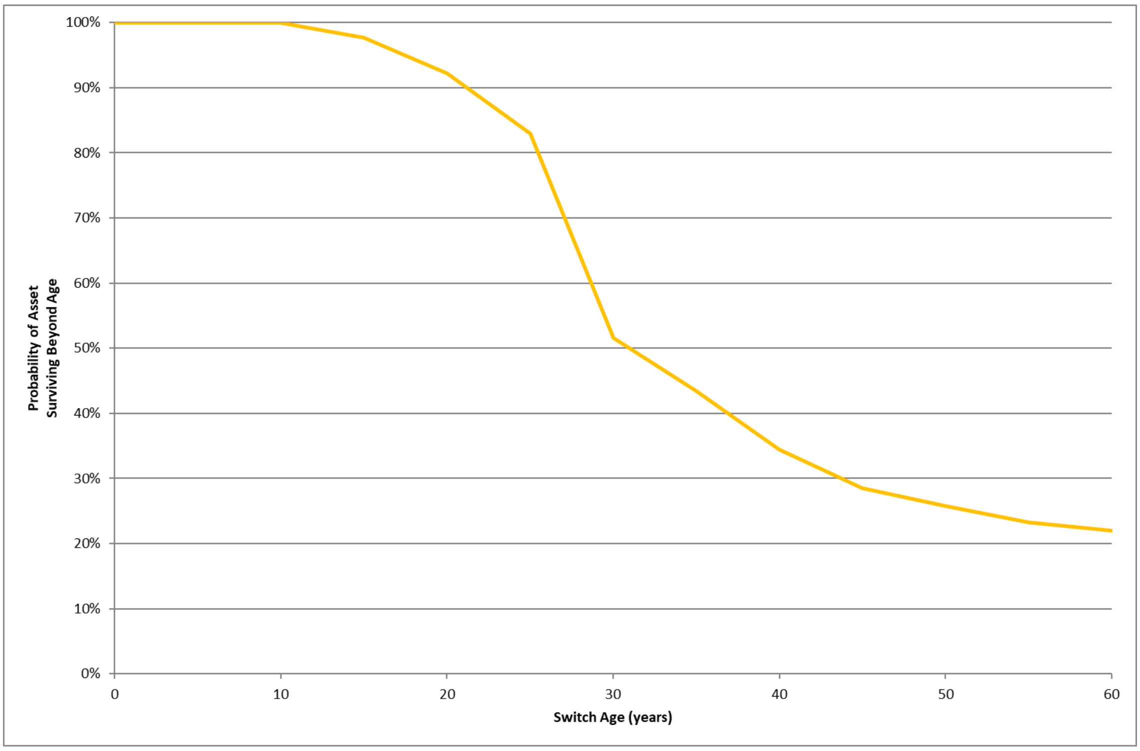


Figure 8-31 Overhead Switch Survival Curve

Renewal and Refurbishment

Any renewal activity on these assets is driven by standard inspection rounds and resultant maintenance activities arise from the identification of corrective work. With the extensive pole and crossarm replacements undertaken over recent years, a large number of overhead switches have now been replaced. Replacement generally occurs as reactive capital expenditure following a poor condition assessment result from the routine inspections, or at the time of pole or crossarm replacement if the condition of the switch justifies this at that time.

The forecast number of overhead switch replacements per year is forecast by rolling the population through the survival curve.

Expenditure Summary for Overhead Switchgear

Table 8-58 details the expected expenditure on overhead switchgear by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Reactive Capital Expenditure	101	105	117	123	138	168	179	177	170	158
Capital Expenditure Total	**101**	**105**	**117**	**123**	**138**	**168**	**179**	**177**	**170**	**158**
Preventative Maintenance	282	282	282	282	282	282	282	282	282	282
Corrective Maintenance	30	30	30	30	30	30	30	30	30	30
Operational Expenditure Total	**312**	**312**	**312**	**312**	**312**	**312**	**312**	**312**	**312**	**312**

Table 8-58 Expenditure on Overhead Switchgear ($K in constant prices)

8.5.8 Other System Fixed Assets

8.5.8.1 Substation DC Systems

Fleet Overview

The DC auxiliary systems provide power supply to the substation protection, control, metering, monitoring, automation and communication systems, as well as circuit breaker tripping and closing mechanisms. The standard DC auxiliary system comprises batteries, battery chargers, DC/DC converters and a battery monitoring system. WELL has a number of historic DC system voltages within its substations, including 24V, 30V, 36V, 48V, and 110V, however, 24V has been adopted as the standard for all new or replacement installations.

Maintenance Activities

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

Activity	Description	Frequency
Inspection and monitoring of battery & charger condition.	Routine visual inspection of batteries, chargers and associated equipment. Voltage check on batteries and charger.	Annually
10 Second battery discharge test.	10-second battery discharge test for battery banks rated less than 65 Ah, measurement and reporting of results.	Annually
Comprehensive battery discharge test.	Comprehensive battery discharge test for battery banks rated 65 Ah and larger, measurement and reporting of results.	2 yearly

Table 8-59 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 economical.

Battery Replacement

WELL has a total of 552 battery banks across 297 sites. Batteries are a critical system for substation operation but are low-cost items. WELL's policy is that all batteries are replaced at 80% of their design life rather than implementing an extensive testing regime. For sites with higher ampere-hour demand, 10-year life batteries are used. For smaller sites or communications batteries where the demand is lower, batteries are installed with five-year lives. WELL is standardising the voltages used for switchgear operation as well as communications equipment as part of primary plant replacement.

Expenditure Summary for Substation Batteries

Table 8-60 details the expected expenditure on substation batteries by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Asset Replacement and Renewal CAPEX	250	250	250	250	250	250	250	250	250	250
Capital Expenditure Total	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**	**250**
Preventative Maintenance	76	76	76	76	76	76	76	76	76	76
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**86**	**86**	**86**	**86**	**86**	**86**	**86**	**86**	**86**	**86**

Table 8-60 Expenditure on Substation Batteries ($K in constant prices)

8.5.8.2 Protection Devices

Fleet Overview

Protection devices are assets that automatically detect abnormal conditions and indicate a potential primary equipment fault. This ensures that the system remains safe and stable, and that damage to equipment is minimised whilst service life is maximised. Protection assets are also installed to limit the number of customers affected by an equipment failure.

On the HV system, there are 1,454 protection devices in operation. The majority of these are electromechanical devices. The remainder use solid-state electronic or microprocessor technology. Protection devices are generally mounted as part of a substation switchboard but can also be housed in dedicated panels.

WELL has assigned a Tier system to differentiate between the various sections of the distribution network as presented in Figure 8-32. This serves to enable a clear reference for asset management planning and expenditure forecasting. The types of protective devices and their applications vary depending on the level of security required and the risk to supply.

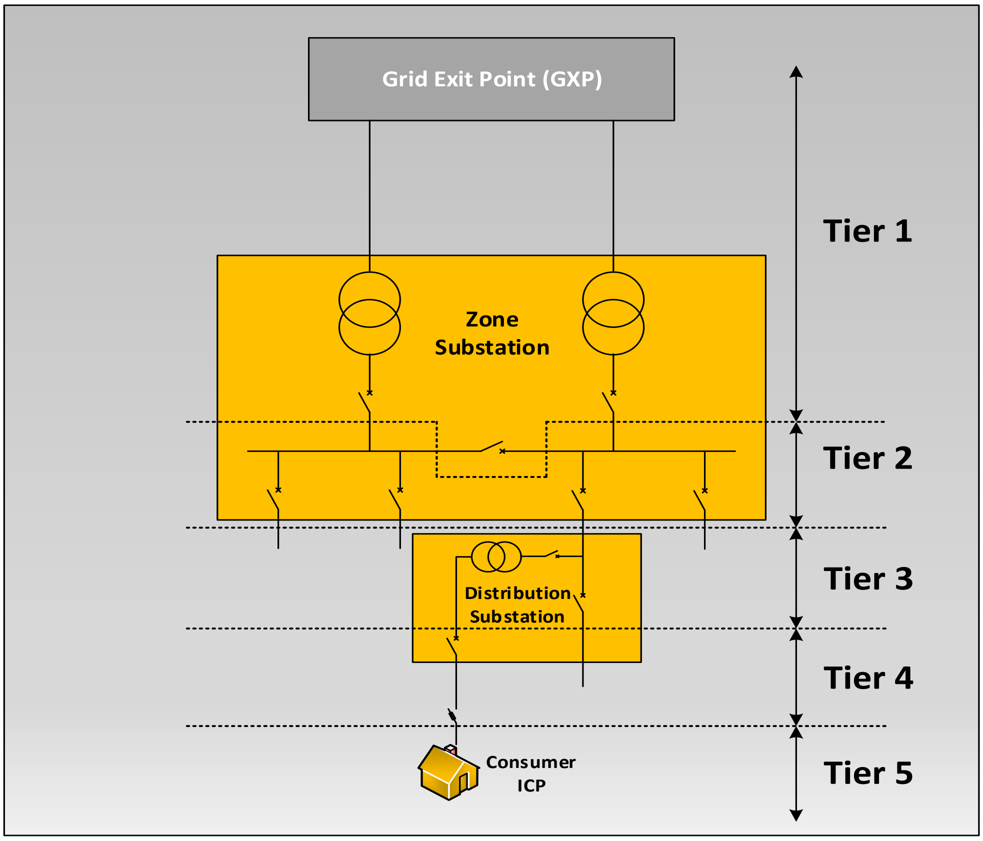


Figure 8-32 WELL Protection Tier System

Differential protection is used on all Tier 1 systems across the network and is also widely used on Tier 2 systems in the Southern Area 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 Area, Tier 2 is generally enabled with OC/EF protection, supplemented by auto-reclosers on rural feeders, and fuses on rural spur lines.

Fuses are used for the protection of 11kV distribution transformers up to 1 MVA, with OC/EF relays protecting larger transformers. Fuses are generally used on the LV system for the protection of cables and LV equipment however Low Voltage Circuit Breakers are also used where larger transformers pose increased arc flash risk or where there are special considerations such as bi-directional power flow.

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 age profiles of these devices are shown in Figure 8-33.

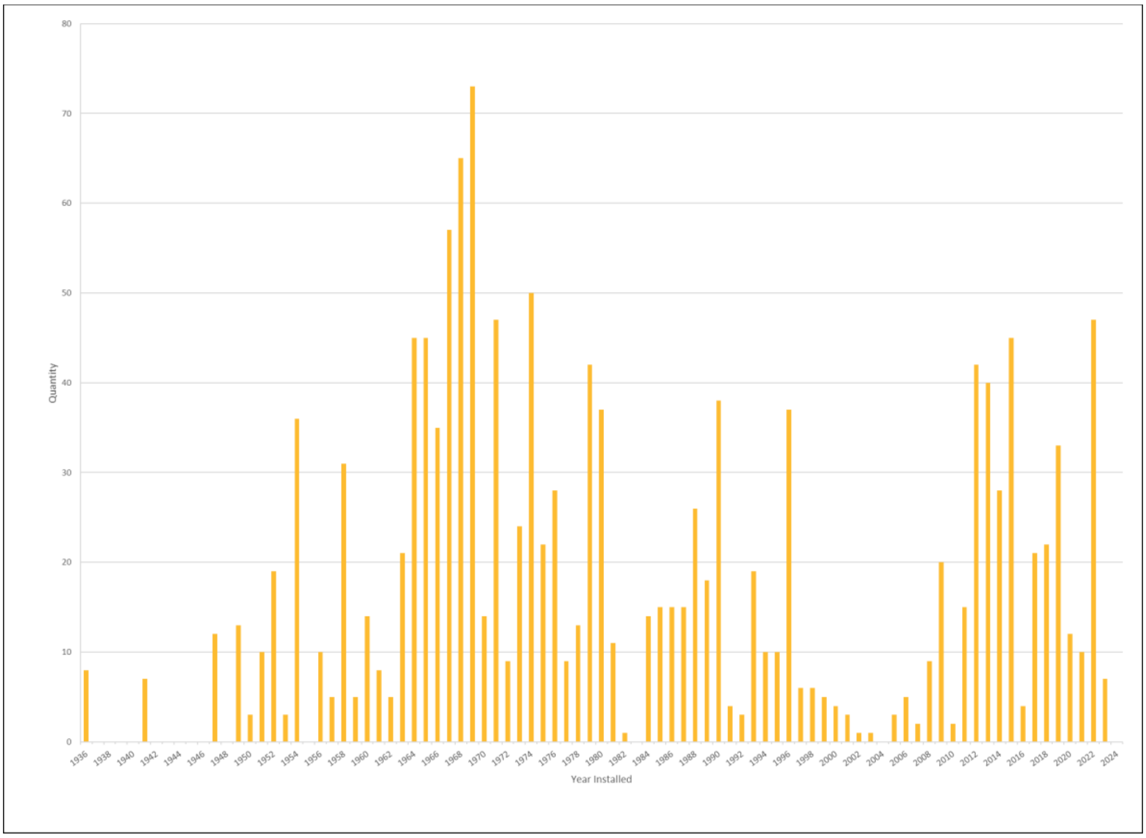


Figure 8-33 Age Profile of Protection Relays

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 the relay using secondary injection. Confirm as-tested settings against expected settings. Update of test record and results into the 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 the 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 the Protection Database.	2 yearly (Tier 1 & 2) 5 yearly (Tier 3)
Numerical Relay Battery Replacement	Replacement of backup battery in numeric relays.	4 yearly (Tier 1 & 2) 5 yearly (Tier 3)

Table 8-61 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.

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 in 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 Authority has reviewed the arrangements for Automatic Under-Frequency Load Shedding (AUFLS), and there is a requirement for EDBs to move from the current two-block scheme to a four-block scheme by June 2025. WELL is replacing the AUFLS relays at a number of its zone substations in order to implement this change.

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

- Ongoing replacement of devices with identified risk;
- Annual preventative maintenance program;
- Tier 1 replacement programme;
- Tier 2 replacement programme;
- Tier 3 replacement programme; and
- AUFLS relay replacements.

In addition to replacement programs, WELL is adhering to a philosophy of continuous improvement by reviewing and optimising protection management processes and creating application guides, testing and commissioning documents.

Expenditure Summary for Protection Relays

Table 8-62 details the expected expenditure on protection relays by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Tier 1 Replacement Programme	463	800	800	800	-	-	-	-	-	-
Tier 2 Replacement Programme	205	-	-	300	600	600	600	600	600	600
Tier 3 Replacement Programme	-	300	300	300	300	300	300	300	300	300
AUFLS Relay Replacement	-	4,458	-	-	-	-	-	-	-	-
Capital Expenditure Total	**668**	**5,558**	**1,100**	**1,400**	**900**	**900**	**900**	**900**	**900**	**900**
Preventative Maintenance	164	164	164	164	164	164	164	164	164	164
Corrective Maintenance	10	10	10	10	10	10	10	10	10	10
Operational Expenditure Total	**174**	**174**	**174**	**174**	**174**	**174**	**174**	**174**	**174**	**174**

Table 8-62 Expenditure on Protection Relays (\$K in constant prices)

8.5.8.3 SCADA and Communications Assets

Fleet Overview

The WELL Supervisory Control and Data Acquisition (SCADA) system comprises a series of communication assets, housed in different locations, and interlinked using several media types. The Master Station is at the top of the topology and there are many other components scaling down to the end device known as the Remote Terminal Unit (RTU). The SCADA Master Station is a GE PowerOn Fusion system, commissioned in early 2016. A legacy Foxboro system has been retained to provide the automatic load control function until an alternative system is implemented. Both the SCADA and Load Control Master Stations are being replaced, with more detail provided in Section 11.

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 sites provisioned for SCADA. More specifically, SCADA is used to:

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

System information is collected by RTUs at each remote location and is transmitted to the SCADA 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 some of the fibre links are WELL owned and others are under lease agreements.

An age profile of SCADA RTUs is shown in Figure 8-34.

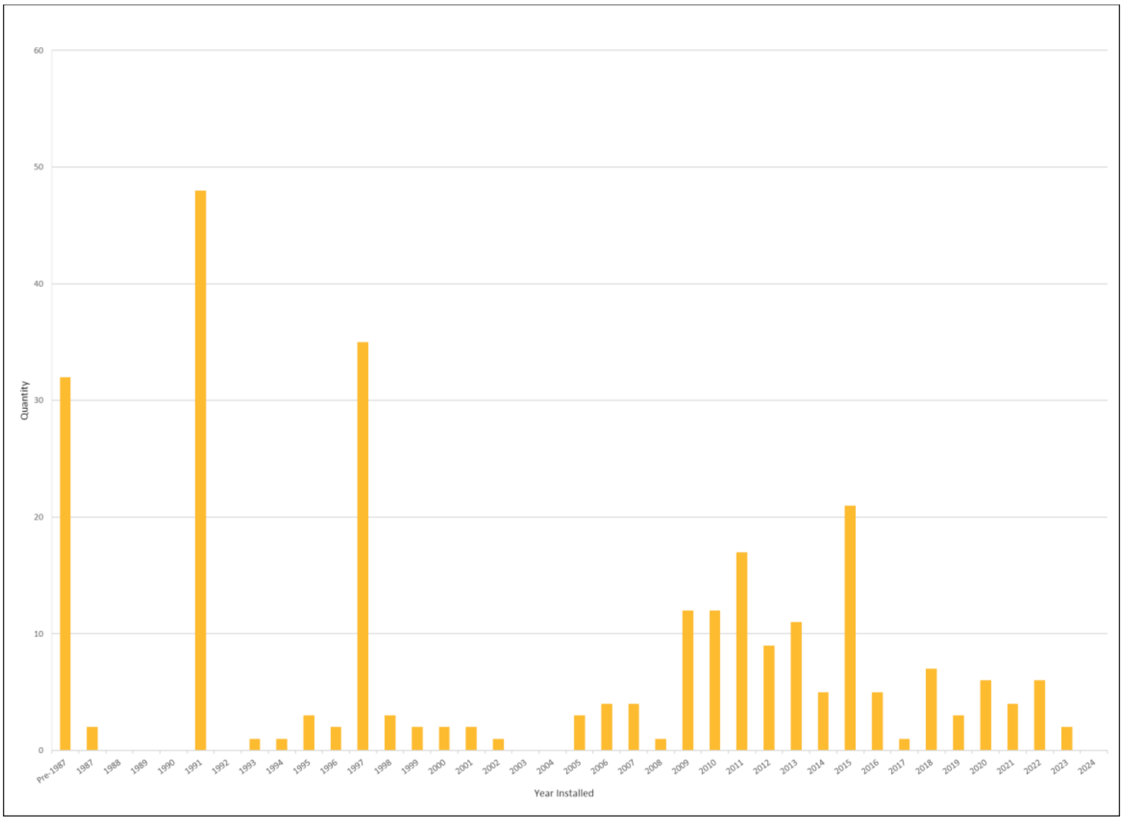


Figure 8-34 Age Profile of SCADA RTUs

To date, WELL has approximately 265 SCADA-provisioned sites, utilising multi-generational RTUs and communication protocols.

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. Maintenance is broken into two categories:

(a) Hardware support is provided as required by Wellington-based maintenance contractors; and

(b) Software maintenance and support are 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 non-critical 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. New sites utilising radio are implemented using public cellular infrastructure on a private APN.

Legacy Remote Terminal Units (RTUs)

Many legacy RTUs remain in service on the network. These legacy devices are no longer manufactured and are difficult to repair, so as they fail they are interchanged with modern alternatives.

Common Alarms

Many Common Alarm units remain in service on the network. These are custom-built devices, placed in non-critical "ringed" distribution substations to give an indication to the NCR of a substation event. These units are not economically viable to repair and have low functionality, and there is an active programme to replace these units with modern RTUs.

PAS Replacement Project

There are two Siemens Power Automation System (PAS) units that act as protocol converters between Siemens IEC61850 field devices located at three sites and the DNP3.0 SCADA master station. The PAS units are now at the end of life and work is underway to replace them.

Renewal and Refurbishment

The asset replacement budget provides for the ongoing replacement of obsolete RTUs throughout the network. Obsolete RTUs that may have a significant impact on network reliability are identified, with replacement priority being given to the zone and major switching substations.

As substation sites are upgraded or developed, and if IP network connections are available, the station RTU is upgraded and moved onto the substation TCP/IP network utilising the DNP3.0 protocol.

If an RTU at a zone substation or major switching point in the network is adjacent to the existing TCP/IP network, consideration is given to upgrading the equipment to allow TCP/IP connection to improve communication system reliability. Furthermore, the TCP/IP infrastructure will also allow other non-SCADA substation-based equipment to be deployed.

The priority of the substation RTU replacement programme will align with other secondary asset replacement programmes. An RTU replacement 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.

Part of WELL's strategy for managing the impact of 11 kV underground cable faults (see Section 8.5.4) is to increase the number of circuit breakers and remote-controlled switches on the underground network. WELL intends to commence a programme of retrofitting ring main units with motor drives and RTUs during DPP4, prioritising the units to be upgraded by their potential reliability impact.

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

- Zone RTU Replacement Programme;
- Common Alarm Replacement Programme;
- Distribution RTU Replacement;
- Substation Data Network Renewal including Conitel replacement;
- Retrofitting SCADA control to existing automation-enabled switchgear, and
- End of Life RTU Replacement (Reactive).

Expenditure Summary for SCADA and Communications Assets

Table 8-63 details the expected expenditure on SCADA and communications assets by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Zone RTU Replacement Programme	1,440	700	-	-	-	-	-	-	-	-
Common Alarm Replacement Programme	253	500	500	500	500	500	500	500	500	500
Distribution RTU Replacement Programme	200	200	200	200	200	200	200	200	200	200
Substation Data Network	1,089	462	324	522	500	500	500	500	500	500
SCADA control retrofits	-	200	200	200	200	200	200	200	200	200
Reactive Capital Expenditure	100	100	100	100	100	100	100	100	100	100
Capital Expenditure Total	**3,082**	**2,162**	**1,324**	**1,522**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**	**1,500**
Corrective Maintenance	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**	**20**

Table 8-63 Expenditure on SCADA and Communications Assets
($K in constant prices)

8.5.9 Other Network Assets

8.5.9.1 Metering

WELL does not own any metering assets on customer premises as these are owned by retailers and metering service provider companies.

WELL-owned check meters are installed at GXPs, and Maximum Demand Indicator (MDI) meters are installed in a number of distribution substations, predominantly those used for street LV supply. MDIs are used for operational and planning purposes only and are considered part of the distribution substation. In future, there may be benefits from accessing smart metering data from customer 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 11.

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.

8.5.9.2 Generators and Mobile Substations

WELL owns six mobile generators and a fixed generator supporting the disaster recovery control room site. WELL makes use of one of the mobile generators at its corporate office and two at its disaster recovery data centres, while the others are used to reduce the impact of outages on customers. WELL also owns two mobile 33/11 kV 10MVA mobile substations and one mobile 11 kV switchboard.

The works contractor provides other generation required for network operations and outage mitigation, where required.

8.5.9.3 Voltage Regulation

Voltage is regulated at the zone substations using Automatic Voltage Regulator Relays (AVRRs) to control the power transformer tap changer. Several sites have been identified as having AVRRs which are no longer supported by suppliers and are a risk upon failure.

8.5.9.4 Load Control Equipment

Fleet Overview

WELL uses a ripple injection signal load control system to inject 475 Hz and 1050 Hz signals into the network for the control of selected loads such as water heating and storage heaters at customer premises, to control street lighting and also to provide legacy tariff signalling on behalf of retailers. All ripple injection is controlled automatically by a Catapult master station but can also be controlled manually at the injection plant in emergencies.

There are 25 ripple injection plants on the network, predominantly located at GXPs and zone substations. The Southern area has a 475 Hz signal injected into the 33 kV network with two static plants 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 nominal 1050 Hz signal injected at 11 kV at each zone substation.

1050 Hz signals are produced by motor generator sets. The signal has a frequency that is lower than 1050 Hz due to a slip in the induction motor. The design slip at full load is 0.7%, giving a signalling frequency range of 1042-1050 Hz under varying loading conditions. The standard receivers used in the Northeast and Northwest areas are tuned to 1042 Hz.

WELL will continue operating its ripple injection system for the foreseeable future. This is due to concerns associated with the reliability, resilience, and speed of proposed alternative hot water control methods that operate over public cellphone networks.

An age profile of the ripple plant is shown in Figure 8-35.

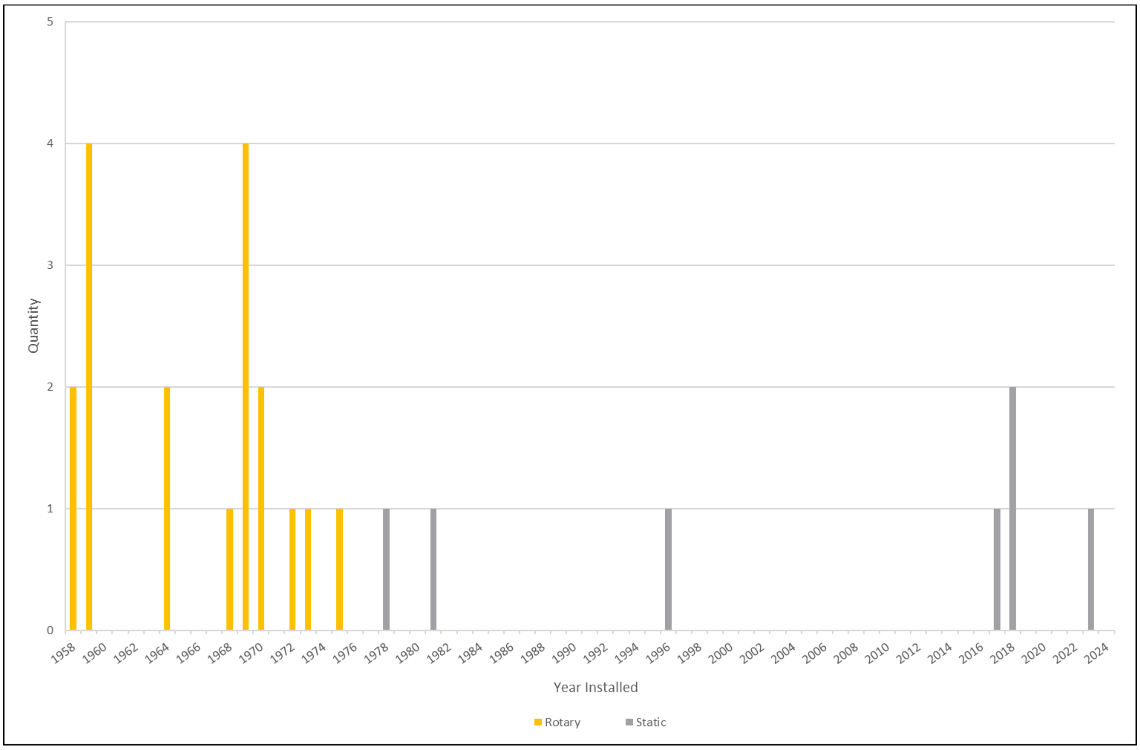


Figure 8-35 Age Profile of Ripple Plant

Maintenance Activities

The following routine planned inspection, testing and maintenance activities are undertaken on load control equipment. WELL owns the injection plants located at substations and the blocking cells at GXPs but does not own the customer receivers.

Activity	Description	Frequency
General Inspection	Check output signal, visual inspection, thermal image and partial discharge scan, and 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 blocking cells at GXPs as required.	5 yearly

Table 8-64 Inspection and Routine Maintenance Schedule for Ripple Plant

Strategic Spares

The spares held for the load control plant are shown in Table 8-65.

Strategic Spares	
Injection plant	A spare 24kVA rotary motor generator set is held for the 11 kV ripple system in the Hutt Valley. A spare 300 kVA static transmitter is held at Frederick Street. An assortment of coupling cell equipment is held in store.
Controllers	A spare Load Control PLC is kept as a strategic spare.

Table 8-65 Spares Held for Load Control Plant

Renewal and Refurbishment

Primary Equipment

The increasing electricity demand resulting from decarbonisation initiatives, and the need to reinforce the network to support that demand, will significantly increase the loading on WELL's injection plants. The fleet will be progressively upgraded with larger units in response to this demand growth.

There was a failure in 2023 of a 1050 Hz motor generator set at the Tawa zone substation that was unable to be repaired. The unit was replaced with a static transmitter. WELL is investigating holding a larger spare static 1050 Hz transmitter as a replacement for the existing rotary spare.

Load Control Master Station

The load control master station was replaced in 2023. This is discussed in Section 11.

Load Control Programmable Logic Controller (PLC)

The load control PLCs are housed at the site of ripple injection and are responsible for coordinating the onsite operation of the ripple plant. These are at the end of their technical life. Some spare parts are available, and units will be replaced either in conjunction with the replacement of their ripple plant, or reactively as they fail and the spares are consumed.

Expenditure Summary for Other Network Assets

Table 8-66 details the expected expenditure on other network assets by regulatory year.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Ripple Injection Plant Renewal	-	750	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Reactive Capital Expenditure	300	300	300	400	400	400	400	400	400	400
AVRR Replacement Programme	200	200	200	200	-	-	-	-	-	-
Capital Expenditure Total	**500**	**1,250**	**1,500**	**1,600**	**1,400**	**1,400**	**1,400**	**1,400**	**1,400**	**1,400**
Preventative Maintenance	68	68	68	68	68	68	68	68	68	68
Corrective Maintenance	100	100	100	100	100	100	100	100	100	100
Operational Expenditure Total	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**	**168**

Table 8-66 Expenditure on Other Network Assets
($K in constant prices)

8.5.10 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.

8.5.10.1 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.

8.5.10.2 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.

8.5.10.3 Protection Relays and Metering

WELL owns 33 kV line 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.

8.5.10.4 SCADA, RTUs and Communications Equipment

WELL owns SCADA RTUs and associated communications equipment at all GXPs.

8.5.10.5 DC Power Supplies and Battery Banks

WELL owns battery banks and DC supply equipment at all GXPs.

8.5.10.6 Load Control Equipment

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

8.6 Asset Replacement and Renewal Summary for 2024-2034

The total projected capital budget for asset replacement and renewal for 2023 to 2033 is presented in Table 8-67. This includes provisions for replacements that arise from faults and 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	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Subtransmission	1,512	12,500	-	8,500	10,000	-	10,000	10,000	10,500	-
Zone Substations	2,460	470	470	470	470	470	470	470	470	5,470
Distribution Poles and Lines	7,142	7,250	7,268	7,145	7,075	6,900	6,813	6,428	6,445	6,323
Distribution Cables	2,705	2,734	2,734	3,206	3,206	3,206	3,206	3,206	3,206	3,206
Distribution Substations	5,486	5,317	5,317	5,537	5,262	5,070	5,070	5,345	5,429	5,869
Distribution Switchgear	6,161	9,518	9,982	6,777	6,537	6,534	6,569	6,570	6,614	6,469
Other Network Assets	4,500	4,562	3,974	4,572	3,850	3,850	3,850	3,850	3,850	3,850
Total	**29,966**	**42,351**	**29,745**	**36,207**	**36,400**	**26,030**	**35,978**	**35,869**	**36,514**	**31,187**

Table 8-67 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 8-68. This budget is relatively constant and is set by the asset strategies and maintenance standards that define inspection tasks and frequencies.

Asset Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Subtransmission	103	103	102	101	101	100	100	100	99	98
Zone Substations	545	545	545	545	545	545	545	545	545	545
Distribution Poles and Lines	685	679	672	673	676	678	676	670	665	659
Distribution Cables	-	-	-	-	-	-	-	-	-	-
Distribution Substations	768	768	768	768	768	768	768	768	768	768
Distribution Switchgear	1,202	1,248	1,369	1,465	1,392	1,507	1,230	1,323	1,401	1,261
Other Network Assets	308	308	308	308	308	308	308	308	308	308
Total	**3,611**	**3,651**	**3,764**	**3,860**	**3,790**	**3,906**	**3,627**	**3,714**	**3,786**	**3,639**

Table 8-68 Preventative Maintenance by Asset Category ($K in constant prices)

The forecast corrective maintenance expenditure by asset category is shown in Table 8-69. This excludes capitalised maintenance, which is instead incorporated into the Asset Renewal and Replacement expenditure forecast in Table 8-67. 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	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Subtransmission	560	560	560	560	560	560	560	560	560	560
Zone Substations	445	445	445	445	445	445	445	445	445	445
Distribution Poles and Lines	996	996	996	996	996	996	996	996	996	996
Distribution Cables	101	101	101	101	101	101	101	101	101	101
Distribution Substations	760	760	760	760	760	760	760	760	760	760
Distribution Switchgear	606	606	606	606	606	606	606	606	606	606
Other Network Assets	140	140	140	140	140	140	140	140	140	140
Total	**3,608**	**3,608**	**3,608**	**3,608**	**3,608**	**3,608**	**3,608**	**3,608**	**3,608**	**3,608**

Table 8-69 Corrective Maintenance by Asset Category ($K in constant prices)

8.6.1 Reliability, Safety and Environmental Programmes for 2023-2033

Asset management expenditure that is not directly the result of asset health drivers is categorised into the quality of supply and other reliability, safety and environmental expenditure. Quality of supply projects target the worst-performing feeders. Other reliability, safety and environmental projects include the BAU seismic programme. The total projected capital budget for these categories is presented in Table 8-70.

Programme	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Feeder Reliability Projects – Lines	875	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Feeder Reliability Projects – Switchgear	1,550	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Switchgear SCADA Control Retrofit	-	200	200	200	200	200	200	200	200	200
Total Quality of Supply	**2,425**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**
AUFLS Relay Replacement	-	4,458	-	-	-	-	-	-	-	-
Total Legislative and Regulatory	**-**	**4,458**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Resilience Expenditure (See Section 11)	725	2,460	650	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	**725**	**2,460**	**650**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 8-70 Reliability, Safety and Environmental Capital Expenditure ($K in constant prices)

8.6.2 Asset Management Expenditure

The total capital and operational expenditure forecasts are shown in Table 8-71 and Table 8-72. 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	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Asset Replacement & Renewal	29,966	42,351	29,745	36,207	36,400	26,030	35,978	35,869	36,514	31,187
Other Reliability, Safety & Environment	725	2,460	650	-	-	-	-	-	-	-
Legislative and Regulatory	-	4,458	-	-	-	-	-	-	-	-
Quality of Supply	2,425	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Total Capital Expenditure on Asset Replacement Safety and Quality	**33,116**	**51,769**	**32,895**	**38,707**	**38,900**	**28,530**	**38,478**	**38,369**	**39,014**	**33,687**

Table 8-71 Asset Management Capital Expenditure Forecast ($K in constant prices)

Operational expenditure forecasts have been adjusted to reflect increasing investment levels and changes in work programmes.

Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Service interruptions & emergency maintenance	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289
Vegetation management	2,263	2,451	2,451	2,451	2,451	2,451	2,451	2,451	2,451	2,451
Routine & corrective maintenance and inspection maintenance	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946
Asset replacement & renewal maintenance	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
Total Network Operational Expenditure	**19,967**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**

Table 8-72 Network Operational Expenditure Forecast ($K in constant prices)

Section 9

System Growth and Reinforcement

9 System Growth and Reinforcement

This section sets out WELL's network development plan over the next 10 years. The purpose of network development is to safely deliver the level of capacity and security of supply required to achieve the service levels and network performance described in Sections 6 and 7.

The New Zealand Emissions Reduction Plan (ERP) was published in May 2022 and has established a number of decarbonisation programmes in order to meet the country's commitment to achieving net-zero emissions by 2050. While the details of some of these programmes are yet to be clarified, particularly around the use of natural gas, electricity has a fundamental role to play in meeting this commitment. For WELL, this will result in a significant increase in demand on the network, particularly relating to the electrification of transport and the transition away from gas as a residential fuel.

The demand forecasts provided in this section include WELL's estimates of the increase in demand resulting from the implementation of the ERP. Specifically, this includes the expected impact of the uptake of electric vehicles, confirmed public transport electrification projects, and an assumption that electricity will play a significant role in replacing gas for residential water and space heating. These forecasts include assumptions about the diversity of this additional demand and the potential for flexibility services to move load away from peak demand periods.

The updated demand forecasts show that over the next ten years, most of WELL's zone substations will exceed the loading limits defined in WELL's security of supply policy. Figure 9-1 shows the increase in maximum demand at WELL's zone substations relative to their rated capacity changes from 2023 to 2033. Loading beyond N-1 limits may be able to be managed using existing tools (for example temporary load transfers or flexibility services) or require an asset upgrade where these tools are insufficient. This illustrates the extent to which decarbonisation will drive the need for WELL to reinforce its network.

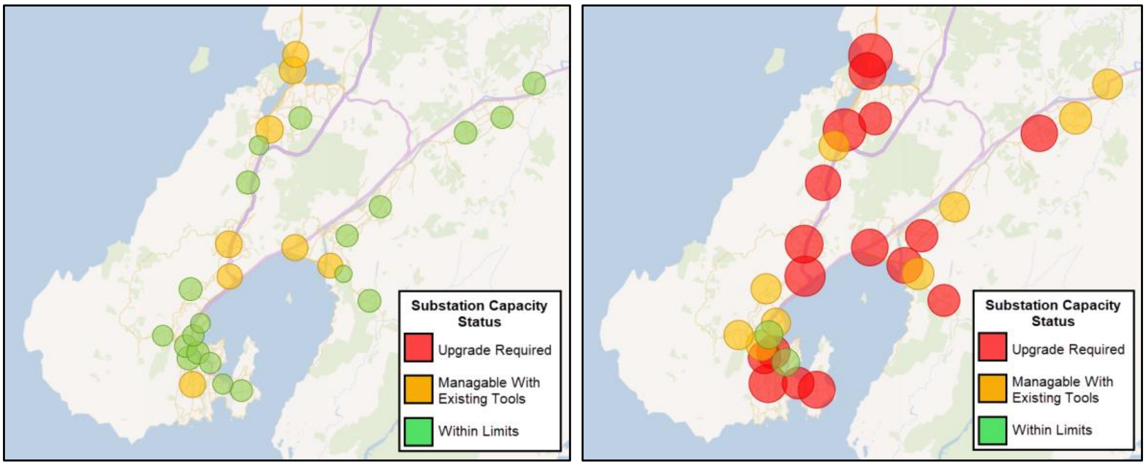


Figure 9-1 – Change in Zone Substation Demand vs Capacity from 2023 (Left) to 2033 (Right)

WELL will need to invest in new capacity to solve these constraints. However, the rate of the demand increase may vary resulting in a re-sequencing of the investment programme. As demand forecasts are refined, load approaches the trigger levels for reinforcement, and unforeseen customer connection requests are included, the location and timing of constraints may change, resulting in significant changes in investment profiles. The risk that this poses to customers is asymmetric, with different levels of risk for WELL building capacity too early versus building it too late. The price paths will need to reflect and accommodate this uncertainty in how they use the AMP investment forecasts.

The forecasts will continue to be refined over time as WELL undertakes further analysis, government policy is clarified, and uptake trends become apparent.

In addition to considering historical growth trends and the impact of decarbonisation, this 2023 AMP forecast includes confirmed and highly likely customer development projects. Other possible customer development proposals signalled but not yet confirmed are indicated in this AMP, although they are not used to set the network development plan. WELL will continue to monitor these developments and propose appropriate network development in response to the expected demand growth.

WELL continues to monitor policy changes and developments in the emerging technologies space. A work programme has been initiated to carry out detailed modelling of the impacts and scope of required network upgrades to inform the funding mechanism, which is discussed in Section 10.

9.1 Network Planning Policies and Standards

The policy and standards underpinning system reinforcement cover the following areas:

- Security criteria – 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.

9.1.1 Security Criteria

The design of WELL's network is based on the security criteria shown in Table 9-1 (subtransmission criteria) and Table 9-2 (distribution criteria).

The security criteria are consistent with industry practice[31] and are designed to:

- Match the security of supply with customer requirements;
- Optimise capital and operational expenditure without a significant increase in supply risks; and

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

- Increase asset utilisation and reduce system losses.

The security criteria accept there is a small risk that supply may be interrupted, and cannot be backfed, if a fault occurs during maximum demand times. This is a balance of risk and cost and is considered a prudent approach rather than increasing costs to customers in order to remove the small risk altogether.

The WELL subtransmission network consists of a series of radial 33 kV circuits from Transpower's GXPs to the zone substations. The subtransmission circuits connect directly to 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 peak demand and provide N-1 security. At the zone substations where the 11 kV bus is normally operated open, there will be a brief interruption to customers following a subtransmission, transformer, or incomer cable fault, while the bus tie is closed. This is considered to satisfy the N-1 security criteria.

Subtransmission

The length of time (defined as a percentage) when the subtransmission network cannot meet N-1 security is defined for each category of customer. Limits are also set on the maximum load that would be lost for the occurrence of a contingency event. The peak demand at a zone substation is calculated based on the security criteria applied at that zone substation. This differs from the anytime maximum demand which is measured over a 30-minute period and can occur as a result of abnormal system operations.

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

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

Table 9-1 Security Criteria for the Subtransmission Network

Distribution

Table 9-2 shows the applicable security criteria for the distribution network.

Type of Load	Security Criteria
CBD or high-density industrial	N-1 capacity for 99.5% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Mixed commercial / industrial / residential feeders	N-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 and including feeders in rural (maybe: Predominantly residential with some rural Feeders)	N-1 capacity for 95% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.
Overhead spurs supplying up to 1MVA urban area	Loss of supply upon failure. Supply restoration is dependent on repair time.
Underground spurs supplying up to 400kVA.	Loss of supply upon failure. Supply restoration is dependent on repair time.
HV direct / LV Supply to customer	Loss of supply upon failure unless the customer specified a higher security requirement. Supply restoration is dependent on repair time.
Publicly available or public service electric vehicle charging or supply	N-1 capacity for 98% of the time in a year. For the remaining times, supply will be restored within 3 hours following an interruption.

Table 9-2 Security Criteria for the Distribution Network

Basis for the criteria

While the reliability of WELL's HV distribution system is high, notwithstanding the difficult physical environment in which the system must operate,[32] in most situations it is uneconomic to design a network where supply interruptions will never occur. Hence, the network is designed to limit the amount of time over a year when it is not possible to restore supply by reconfiguring the network following a single unplanned equipment failure. This approach recognises that electricity demand on the network varies according to the time of day and season of the year and that the time over which the system is exposed to its maximum demand is very small.

The security criteria do not apply to faults on distribution transformers, the low voltage network, or to failures of connection assets used to supply individual customers, which are typically designed for 'N' security. In such situations, an interruption will last for the time taken to complete 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 12) but, when they occur, longer supply interruptions than shown in the tables are possible.

[32] 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.

Most of the 11 kV feeders in the Wellington CBD, in some locations around Wellington city suburbs, and in the Porirua commercial centre are operated in a closed ring configuration with radial secondary feeders interconnecting neighbouring rings or zone substations. This arrangement provides a high level of security and hence a high level of supply reliability. The urban 11 kV network outside these areas typically comprises radial feeders with a number of mid-feeder switchboards with circuit breakers.

Most of the radial feeders are connected through normally open interconnectors to other feeders so that, in the event of an equipment failure, supply to customers can be switched to neighbouring feeders. To allow for this flexibility, distribution feeders are not operated at their full thermal rating under normal system operating conditions. The maximum feeder utilisation factor at which WELL operates the distribution feeders during normal and contingency operation is identified in Table 9-3. This is a guideline limit and signals the point where greater analysis is required. The actual post contingency loading and implementation of any required solutions is determined using contingency analysis.

Feeder Type	Pre-Contingent Loading	Post-Contingent Loading
Two Feeder Ring	50%	100%
Three Feeder Ring	67%	100%
Four Feeder Ring	75%	100%
Radial Feeder with Backfeeds	67%	100%
Radial Spur without Backfeeds	100%	-

Table 9-3 11 kV Feeder Utilisation during Normal and Contingency Operation

A customer may desire a level of security above or below that offered by a standard connection. Should this arise, WELL conducts a risk assessment to determine whether the proposed customer connection will adversely impact levels of security for existing customers, and the reputational risk to WELL for the customer's services being interrupted. If the proposed connection does not impact existing customers, WELL may offer a range of alternatives that provide different levels of security at different costs, to allow the customer to make an informed decision regarding the price/quality trade off. The customer can then choose to pay for an appropriate level of security to meet their needs for the load that is being supplied.

9.1.2 Voltage Levels

Subtransmission voltage is nominally 33 kV in line with the source voltage at the supplying GXP. The voltage used at the distribution level is nominally 11 kV. The LV distribution network supplies the majority of customers at a nominal 230 V single phase or 400 V three phase. By agreement with customers, 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 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 customers.

The 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. Flexibility services may be required in future to implement suitable power quality response modes to meet supply quality requirements.

9.1.3 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. New switchgear is typically rated for 25 kA for use within zone substations and 21 kA for use within the distribution network.

9.1.4 Power Factor

All connected customers are responsible for ensuring that their demand for reactive power does not exceed the maximum level allowed, or the power factor limits specified in WELL's network pricing schedule and connection requirements. The power factor of a customer's load measured at the metering point must not be lower than 0.95 lagging at all times. Corrective action may be requested by WELL if the customer's power factor falls below this threshold.

9.1.5 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. High levels of harmonic distortion can cause power quality problems for nearby customers, and can reduce the capacity of transformers. It is common to use a single quantity, Total Harmonic Distortion (THD), as a measure of the magnitude of harmonic distortion. Current and voltage harmonic levels are to be within the 5% THD limit specified in the Electrical Safety Regulations 2010 at the point of supply to the customer.

9.1.6 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.

There is no standardisation of high voltage (HV) network augmentation because these are dependent on the customer's specific requirements for the project.

9.1.7 Standardised Cost Model

The implementation of a standardised cost model enables efficient project cost estimation. WELL is currently updating its standardised cost model, using costs incurred by previously completed projects as a guide for future project costs. This standardised cost model has been utilised to estimate costs for future network growth projects described in this Chapter.

The standardised cost model is under continual improvement, as completed projects are added to the input to provide updated costs for building block items.

9.1.8 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; 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).

9.1.9 Non-Network Solution Policy

Non-network solutions include load control, demand-side management solutions, and network reconfigurations.

WELL's load control system is used to reduce maximum demand on the network by moving hot water demand to low load periods. This has the effect of deferring demand-driven network investments.

There is also uncertainty with the fast-changing nature of the emerging technologies. WELL's approach is described in Section 10. To date the cost of implementing emerging technologies have been found to be significantly higher than traditional network-based solutions. WELL will continue with the development of a future pricing roadmap to keep the network efficient and enable the introduction of new technology with minimal network impact.

The options available typically include:

- Open point shifts using existing infrastructure to reduce loading on highly loaded feeders;
- Operational changes to better utilise existing network capacity over the 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 evaluated before any network investment. WELL monitors feeder loading using SCADA alarm limits to provide indication prior to thermal overload of assets. Where there is a risk of exceeding the thermal limits due to equipment failure or constraints, network controllers are able to:

- Initiate shedding of hot water load to move load away from maximum demand periods; and
- Fine-tune network open points to optimise feeder loading and feeder customer numbers.

9.1.10 Impact of Distributed Energy Resource

The magnitude of distributed energy resources (DER) installed in the WELL network is relatively low[33] although there is increasing availability of distributed generation, energy storage, and flexible demand.

Given the intermittent nature of DER and the uncertainty of many DER projects, a conservative approach is taken when assessing their impact. This is often based on a worse-case scenario. Any investment decisions will only consider DER where the resource is deemed reliable and the DER project is certain.

9.1.10.1 Connection Policy

WELL welcomes enquiries from third parties interested in installing embedded generation or storage capacity in its network. WELL has a Distribution Code and Network Connection Standard that includes the procedures for assessment and connection of distributed generation in line with Part 6 of the Electricity Industry Participation Code 2010.

For each third-party request for new generation or storage on the network, WELL conducts a risk assessment for the new connection. The location, timing, and scale of the new connection are assessed using network planning tools to identify possible risks and/or benefits for the scheme. Part of this risk assessment also quantifies the uncertainty around the third-party scheme. WELL's processes regarding quantifying uncertainty of future step changes is described in Section 9.2.1.2.

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 customers;
- Any payments made to third parties must be linked directly to the provision of a service that gives the required technical and commercial outcomes;
- Commercial arrangements must be consistent with avoided cost principles; and
- Ability to provide visibility of local network conditions where the DER is managed by a provider.

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 customers.

Information about connecting distributed generation is available on the WELL website – www.welectricity.co.nz or by calling 0800 248 148.

9.1.11 Asset Capacity Definition

Primary assets in WELL network are classified into the following hierarchy of categories with planning criteria and operational requirements for the different assets shown in Table 9-4.

[33] Installed capacity, excluding standby generation and Mill Creek (connected at 33 kV), is 6.6% of the system maximum demand.

Primary Asset Categories	Asset Boundary	Security Planning Criteria
Tier 0 – Upstream Asset	GXP Feeder CB Cable Termination and above	National Grid Planning Criteria
Tier 1 – Subtransmission	From GXP CB Cable Termination to ZS 11 kV Bus before Feeder CB	Subtransmission Security Criteria, Maximum Continuous Branch Rating (MCBR)
Tier 2 – HV Feeder Distribution	From ZS Feeder CB to Distribution Substation HV Distribution Substation Ring Switch before teed connection to HV Load switch	Distribution Security Criteria, MCBR
Tier 3 – HV Distribution Substation	From Distribution Substation HV switch to LV Bus	Distribution Security Criteria, MCBR
Tier 4 – LV Feeders	From LV Feeder switch to customer demarcation point	Distribution Security Criteria, Peak demand and After Diversity Maximum Demand (ADMD), MCBR
Tier 5 – Customer Assets (HV direct or LV)	From network demarcation point	Peak demand, Customer provided equipment rating

Table 9-4 Security Criteria for the Distribution Network

In general, for 11 kV and 33 kV network planning purposes, the maximum continuous ratings are used, whereas the cyclic ratings are used for planned operational activities and the emergency overload ratings are for unplanned contingency events.

Asset capacity is further defined as follows:

- Power transformers – The transformer ratings include the continuous asset capacity (based on a continuous uniform load profile), the cyclic capacity and a short duration (2-hour) emergency overload rating (dependent on the maximum operating temperature of the transformer);
- Subtransmission cables/lines – Thermal conductor capacity is determined through CYMCAP modelling, considering the effect of soil thermal resistivity, the load profile and resulting thermal inertia, mutual heating due to adjacent conductors and configuration of the installation. Soil and ambient temperature variations between seasons are also allowed for, providing a set of normal, cyclic and emergency ratings;
- Maximum Continuous Branch Rating (MCBR) – This is determined based on the lowest rated component of the circuit, i.e. a transformer may be rated to 36 MVA while the supplying cable is only capable of 21 MVA and 17 MVA during winter and summer respectively. Thus the effective MCBR is limited to the seasonal rating of the cable;
- LV distribution transformers and circuits – Asset capacity in this category is largely driven by the usage pattern and demand response from individual customers. Section 10 outlines the development plans and trial projects that have a direct interface with LV connections.

The capacity of all HV network elements is modelled in the DigSILENT PowerFactory network model providing a tool to analyse network loading against the security standard.

9.2 Demand Forecast 2024 to 2033

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 peak demand forecast for the network.

Peak demand is forecast to grow in most areas of the network, driven by decarbonisation and new commercial and residential developments. There is also a strong correlation between peak demand and seasonal 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.

9.2.1 Demand Forecast Methodology

There is a negative correlation between WELL's total network demand profile and the ambient temperature, with the system maximum demand occurring on the coldest days in winter. In addition, the rating of some network assets such as cables can vary depending on ambient temperature conditions.

WELL develops separate summer and winter demand forecasts using historical trends in peak demand with the addition of confirmed future step changes as follows:

1. For each zone substation, historical summer and winter demand trends are analysed to establish:

    a) an average peak demand forecast growth rate based on the subtransmission security criteria defined in Table 9-1 (i.e. 99.5th percentile for zone substations within the CBD and 98th percentile for all other zone substations); and

    b) a high and low variance from the average peak demand to determine a band of uncertainty in the forecast. The high and low variance includes:

        - high and low population growth scenarios indicated by local government;
        - confirmed and all known highly likely future step change demand; and
        - confirmed and all known highly likely future EV/PV developments. Climate change policies will have an impact on the rate and timing of accelerated EV/PV adoption. WELL's LV Visibility projects (discussed in Section 10.3.2.1) will help establish investment trigger levels.

2. An additional scenario consisting of signalled possible future step changes in demand is added to the high variance for a sensitivity assessment.

At the subtransmission level, the 60th percentile between the high and low range of the summer and winter peak demand forecast values is used for planning purposes and is termed the Likely Peak Demand (LPD).

The 60th percentile allows for a sufficient margin of error given the load at risk and the scale of augmentation investment typically required when a constraint is identified at the subtransmission level. This is plotted against the applicable N-1 subtransmission capacity constraints to determine the subtransmission security of supply.

The growth scenarios are aggregated 'bottom-up' from feeder level to provide GXP, regional, and system wide forecasts allowing for diversity at each level. An overview of the demand forecast methodology is shown in Figure 9-2.

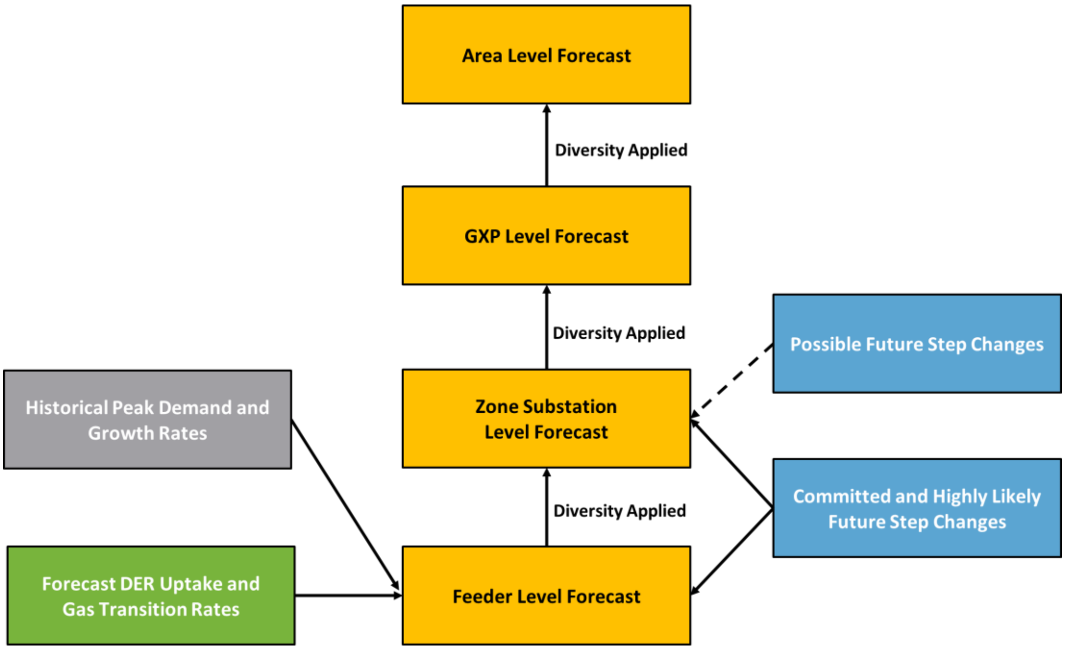


Figure 9-2 Demand Forecasting Methodology

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

9.2.1.1 Forecasting Assumptions and Inputs

The peak demand forecast for the current planning period is based on the following assumptions:

- The use of load control is assumed to remain as per current practice;
- No allowance is made for any significant demand changes due to major weather events or unforeseen network conditions causing significant outages or abnormal operation of the network;
- The impact from distributed generation and new decarbonisation loads such as the gas transition is included, as discussed in Section 10, and
- 5-minute 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 peak demand, the forecast is based on the following information and applies assumptions listed earlier in this section:

- Step change loads, based on confirmed and highly likely customer connection requests, are included in the forecast;

- Diversity factors[34] that provide peak coincident demand are calculated from historical data; and
- Typical demand profiles based on the majority load type in the zone.

These assumptions, data sets and trend analysis are reviewed each year and the expected impacts of any changes are incorporated into the forecast.

9.2.1.2 Step Change Loads

Confirmed and highly likely step change loads are accounted for in the load forecast. These step-change loads may be the result of:

- Major developments that introduce large new loads onto the network with a total connection capacity above 450 kVA or ADMD capacity above 200 kVA;
- New electricity generation that is expected to materially reduce peak demand; or
- Load reductions caused by the movement or closure of businesses.

Known step changes are categorised into the following three groups based on the level of uncertainty:

- C1: network connection offer signed, or signalled by the developer that is close to or is highly likely to be having a contract signed.
- C2: from local council plans assessment of development potential that is close to eventuating or is highly likely to proceed, or signalled by the developer still at exploring development options and WELL has not received an application for connection.
- C3: Speculative – based on potential trends.

Scenarios including each uncertainty category have been modelled in this AMP. Only the C1 scenario is used to determine network constraints. However, C2 and C3 scenarios have been used to inform the priority of the constraint and the scope of the solutions.

The 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 months in advance.

9.2.2 Typical Load Profiles

Typical annual demand profiles for the CBD and residential loads are shown in Figure 9-3 and Figure 9-4 respectively. 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.

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

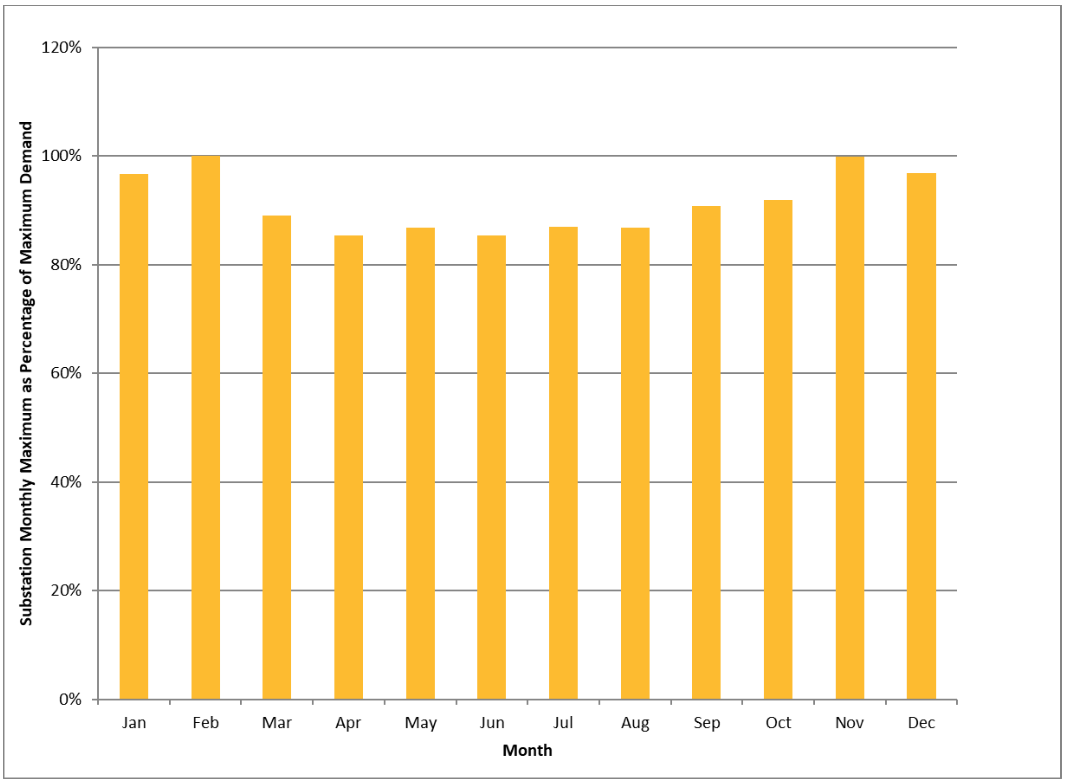


Figure 9-3 Typical CBD Monthly Peak Load Profile

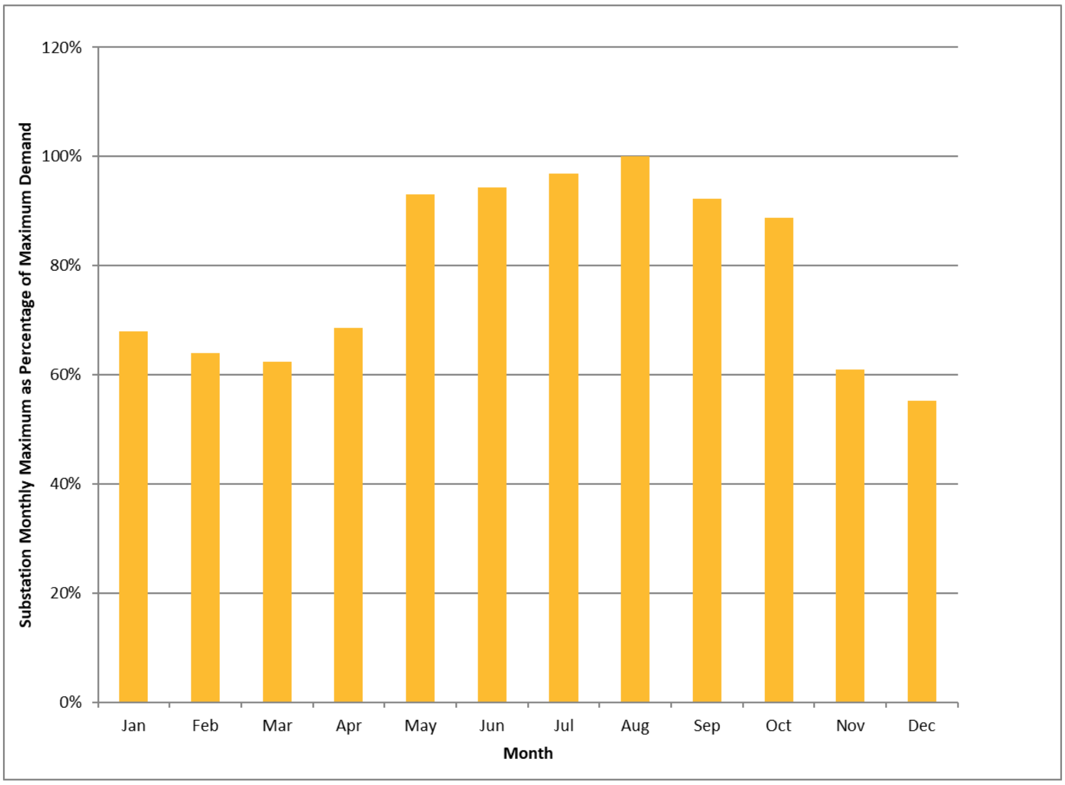


Figure 9-4 Typical Residential Monthly Peak Load Profile

Typical daily demand profiles are shown in Figure 9-5 and Figure 9-6. 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 especially for the winter period. These profiles are subject to change as the uptake of electric vehicles and demand management technologies changes over time.

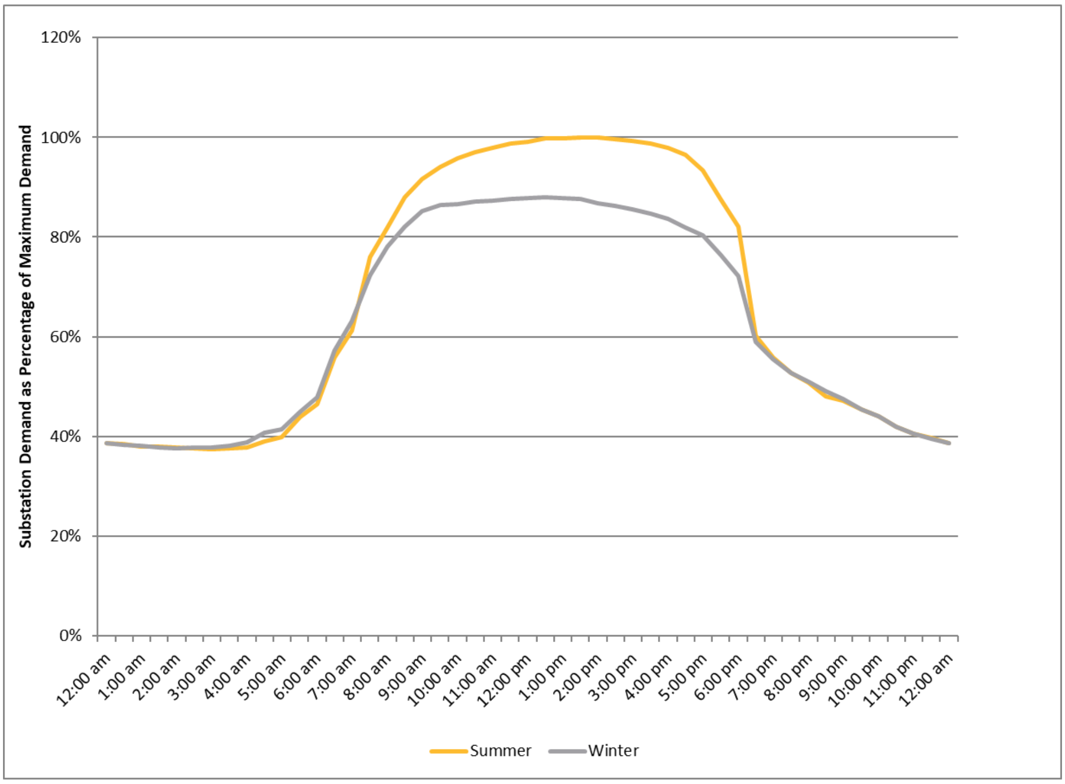


Figure 9-5 Typical CBD Zone Substation Daily Load Profile

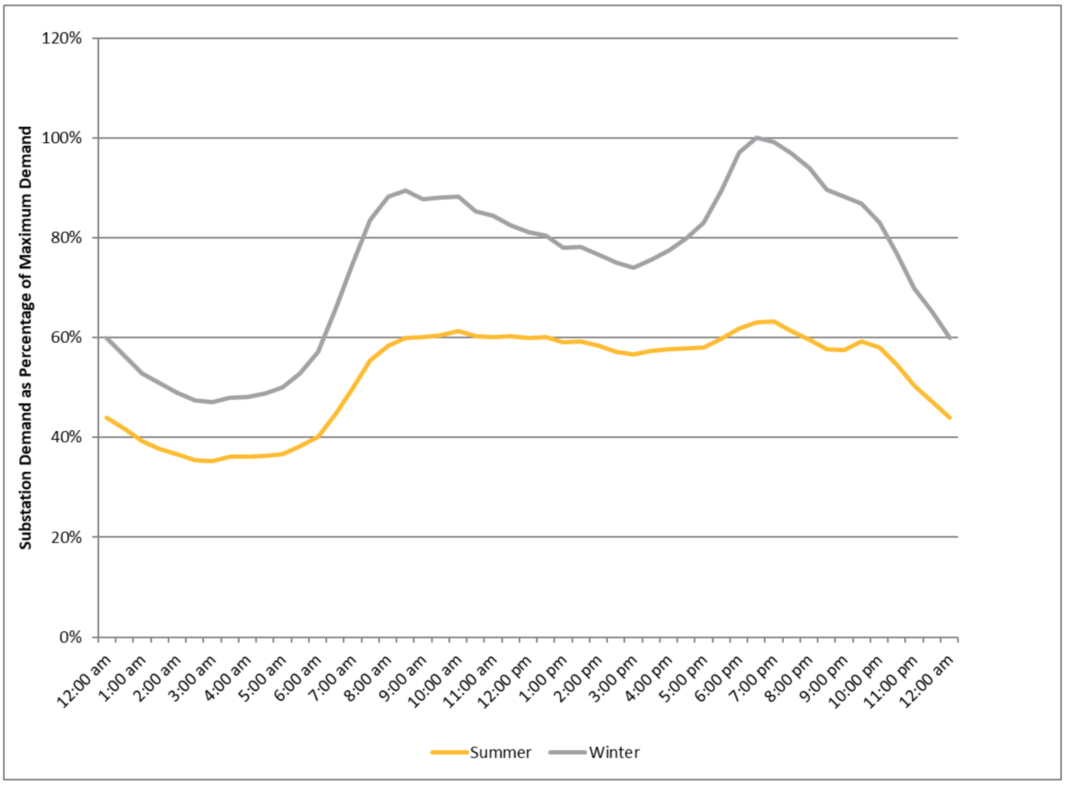


Figure 9-6 Typical Residential Zone Substation Daily Load Profile

9.2.3 Wellington Regional Maximum Demand Forecast

Table 9-5 shows the network maximum demand forecast to 2033. These figures assume an average winter. In practice the actual maximum demand will be influenced by the rate of decarbonisation of transport and heating, customer EV charging behaviour, and whether the winter is milder or colder than average.

Network	Maximum Demand (MW)										
	2023 Actual	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
System Maximum Demand (MW)	536	579	623	651	672	693	713	732	752	770	789

Table 9-5 Forecast 98th Percentile of Network Demand

Table 9-6 shows the contribution of each GXP and DG to the 2023 winter maximum demand.

Location	2023 Coincident Maximum Demand (MW)													
	Central Park	Gracefield	Haywards	Kaiwharawhara	Melling	Pauatahanui	Takapu Road	Upper Hutt	Wilton	Mill Creek	Wellington Wind	Silverstream	Southern Landfill	Other Small DG	Total
Coincident Maximum Demand (MW)	140	56	32	25	52	16	87	28	40	56	0	2	0	0	**536**

Table 9-6 2023 Coincident Maximum Demand

The maximum network demand is expected to grow at a rate of approximately 8% for the next two years, with an average growth rate of approximately 5.3% p.a. over the next five years. The growth includes step change loads such as:

- Committed or highly likely public transport electrification upgrades and new EV charging stations within the Wellington Electricity network;
- Planned residential developments in the Porirua Northern Growth Area, Churton Park, Aotea, Whitby, Grenada North and Upper Hutt areas;
- Expansion plans for a number of commercial and industrial customers; and
- Beyond five years, the rate of growth in peak demand is expected to average 2% per year, driven by the uptake of new technologies such as EVs, and a reduction in residential and commercial gas connections.

9.2.4 Network Area Step Change Development

This section provides a high level summary of confirmed local step change development in each network area.

9.2.4.1 Southern – Step Change Developments

Peak demand in the Southern Area has been flat or in decline in recent years but is expected to increase due to public transport electrification upgrades and a number of new buildings planned over the coming years.

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

Confirmed and highly likely developments in the Southern Area include:

- Public transport electrification upgrades and new EV charging stations;
- New government commercial buildings in Thorndon;
- Residential and commercial development within the Wellington CBD;
- Building decarbonisation;
- Industrial, commercial and residential development in Miramar; and
- Residential and commercial development in Rongotai and Wellington's southern coast.

9.2.4.2 Northwestern - Step Change Developments

The Northwestern Area is continuing to grow organically with the strongest level of residential development within WELL's network. There is relatively high interest for new residential subdivisions in the suburbs of Kenepuru, Whitby, Grenada North and Churton Park. The Plimmerton Farms development is forecast to be a significant area of growth.

Confirmed and highly likely developments in the Northwestern Area include:

- Public transport electrification upgrades;
- Housing New Zealand plans to build an additional 1,500 units over the next 10 years in Eastern Porirua, expected to contribute an average of 300 kVA annually to peak demand;
- Residential development north of Plimmerton, the Pauatahanui-Judgeford area, and Whitby;
- Industrial development in Porirua, Tawa, and Judgeford; and
- Commercial development in Grenada North.

There is limited capacity and HV supply coverage around the existing network boundaries, particularly in Titahi Bay, Plimmerton, and Pauatahanui. WELL will work closely with customers on network expansion requirements for new connections and capacity upgrade projects.

9.2.4.3 Northeastern - Step Change Developments

Peak demand in the Northeastern Area is expected to marginally increase due to localised residential and commercial developments. This is driven by planned residential subdivisions and expansion plans of industrial customers in the Trentham and Maidstone zone substation supply areas.

Confirmed and highly likely developments in the Northeastern Area include:

- Public transport electrification upgrades;
- Residential developments in Upper Hutt, Maymorn, Manor Park, Naenae, Waterloo, Wainuiomata, and Wallaceville;
- Commercial and residential developments in Petone;
- Commercial developments in Trentham and Taita; and
- Expansion of industrial loads in Gracefield and Seaview.

There is limited capacity and 11 kV supply coverage around the existing network boundaries, particularly in Upper Hutt and Wainuiomata. WELL will work closely with customers on network expansion requirements for new connections and capacity upgrade projects.

9.2.5 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 9-7 shows the GXP level forecast by area and Table 9-8 shows the zone substation level forecast by area. For both tables, the base maximum demand value for the forecast is for the last 12 months and area totals are coincident peak demand values.

Area	GXP[35]	Actual and Forecast Peak Demand[36] (MVA)										
		2023 Actual	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Southern	Central Park 33 kV	121	138	148	158	162	168	172	176	180	184	188
	Central Park 11 kV	19	19	21	22	22	23	23	24	24	25	26
	Wilton 33 kV	40	45	47	49	50	52	53	54	56	57	59
	Kaiwharawhara 11 kV	25	28	29	33	41	42	43	53	54	54	55
Northwestern	Pauatahanui 33 kV	16	17	20	22	23	24	25	26	27	28	29
	Takapu Road 33 kV	87	97	109	115	119	124	128	133	138	143	147
Northeastern	Gracefield 33 kV	56	63	67	72	75	78	81	85	88	91	95
	Haywards 33 kV	16	20	23	25	26	28	30	31	31	32	33
	Melling 33 kV	30	32	36	48	49	50	51	53	54	56	57
	Upper Hutt 33 kV	28	31	33	35	36	36	37	38	38	39	40
	Haywards 11 kV	16	19	25	26	29	30	31	32	33	34	35
	Melling 11 kV	22	24	26	26	27	28	28	29	30	30	31

Table 9-7 Wellington Area GXP Level Forecast

[35] Transpower's published P90 forecasts at the GXP level allow for a large margin of uncertainty, prudent for transmission level planning and as such, are not consistent with WELL's forecasts which are less conservative for the purposes of subtransmission and distribution planning.
[36] Forecast values are for the normal growth average seasonal temperature case correspond to the 60th percentile deduced from the peak demand range and include step change loading due to planned load transfer or confirmed customer connections.

Area	GXP	Actual and Forecast Peak Demand[37] (MVA)										
		2023 Actual	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Southern	8 Ira Street	16.2	20.3	23.8	27.5	29.8	30.9	32.1	33.3	34.0	34.7	35.4
	Evans Bay	12.6	16.9	17.6	18.3	18.7	20.8	21.4	22.0	22.6	23.2	23.8
	Frederick Street	25.8	30.2	32.4	34.4	35.4	36.4	37.5	38.6	39.8	41.0	42.1
	Hataitai	15.8	16.3	16.7	17.1	17.3	17.6	17.9	18.2	18.6	18.9	19.2
	Palm Grove	24.1	26.3	30.2	33.0	33.6	34.3	35.0	35.7	36.5	37.3	38.0
	Terrace	22.9	24.6	25.1	25.6	25.8	26.1	26.5	26.8	27.3	27.7	28.1
	University	17.6	19.1	19.5	19.9	20.2	20.5	20.9	21.3	21.7	22.0	22.4
	Nairn Street	21.4	21.8	23.9	24.6	25.2	25.8	26.4	27.1	27.8	28.4	29.1
	Karori	14.3	15.0	17.0	17.5	18.0	18.4	18.9	19.4	19.9	20.4	20.9
	Moore Street	19.0	23.2	24.0	25.5	26.1	26.8	27.5	28.3	29.1	29.9	30.7
	Waikowhai Street	13.5	13.7	14.1	14.5	14.8	15.1	15.4	15.7	16.1	16.4	16.8
Northwestern	Mana	9.0	9.3	9.7	10.0	10.3	10.7	11.0	11.4	11.7	12.1	12.4
	Plimmerton	8.4	9.1	12.3	12.7	13.5	14.2	15.0	15.8	16.6	17.4	18.2
	Johnsonville	20.3	21.4	22.4	23.4	24.3	25.2	26.1	27.0	28.0	29.0	30.0
	Kenepuru	11.2	13.7	15.3	16.1	16.6	17.3	17.9	18.6	19.4	20.1	20.8
	Ngauranga	11.1	12.5	15.3	16.2	16.8	17.5	18.3	19.0	19.9	20.7	21.5
	Porirua	21.7	24.6	29.1	30.6	31.9	33.2	34.6	36.1	37.5	38.5	39.4
	Tawa	14.5	16.1	19.0	20.2	21.1	21.9	22.6	23.3	24.1	24.9	25.7
	Waitangirua	13.9	15.1	16.0	17.2	17.7	18.2	18.8	19.3	20.0	20.6	21.1
Northeastern	Gracefield	10.7	13.4	15.6	17.7	19.4	21.3	22.6	24.5	26.0	27.5	29.0
	Korokoro	18.8	20.6	21.3	22.9	23.4	24.0	24.6	25.2	25.8	26.4	27.1
	Seaview	15.1	15.9	16.8	17.8	18.3	19.0	19.7	20.5	21.3	22.1	22.8
	Wainuiomata	17.7	19.4	20.0	20.7	21.2	21.8	22.9	23.5	24.2	24.8	25.5
	Trentham	16.6	20.6	23.4	25.0	26.8	28.7	30.4	31.0	31.7	32.3	33.0
	Naenae	15.0	16.0	16.8	17.3	17.6	17.9	18.3	18.6	19.0	19.4	19.8
	Waterloo	16.7	17.7	20.8	21.6	22.2	22.9	23.5	24.3	25.0	25.8	26.5
	Brown Owl	16.0	17.5	18.1	18.6	18.8	19.1	19.3	19.6	19.9	20.1	20.4
	Maidstone	14.7	16.5	18.6	19.4	19.8	20.3	20.7	21.2	21.7	22.2	22.7

Table 9-8 Wellington Area Zone Substation Level Forecast

9.3 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 is largely electrically independent and has a different set of challenges however planning for each network area uses a consistent methodology.

The discussion for each area is structured in accordance with the network hierarchy of GXP level requirements, subtransmission and zone substations and then distribution level investments. The GXP level discussion has been developed with reference to Transpower's Transmission Planning Report (TPR) and other formal discussions with Transpower regarding their proposed development plans.

The NDRP for each network area is described in the following respective sections. Each section provides a summary of the NDRP and is structured as follows:

- Potential GXP developments;
- Identified subtransmission development needs;
- Identified HV distribution network development needs; and
- A summary of the network development plan.

The total expenditure profile from these plans is summarised in Section 9.8.

[37] 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.

9.4 Southern Area NDRP

This section provides a summary of the Southern Area NDRP.

9.4.1 GXP Development Plans

The Southern network is supplied from four GXP points at three locations, Central Park, Wilton and Kaiwharawhara. Transpower owns the supply transformers at the GXPs. The transformer capacity and the peak system demand are set out in Table 9-9. The forecast in Table 9-9 considers only committed developments.

GXP	Continuous Capacity (MVA)	Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2023	2033
Central Park 33 kV	2x100 1x120	2 x 108/112 1 x 146/147	121	188
Central Park 11 kV	2x25	29/30	19	26
Wilton 33 kV[38]	2x100	103/110	40	59
Kaiwharawhara 11 kV	2x30	38/38	25	55

Table 9-9 Southern Area GXP Capacities

The development needs at each GXP are discussed below.

9.4.1.1 Central Park GXP

The peak demand on the Central Park GXP in 2023 was 121.2 MVA.

The Central Park 33 kV bus is normally operated closed and supplies eight zone substations via double 33 kV subtransmission circuits, and two 33/11 kV transformers. The zone substations supplied from Central Park GXP are:

- 8 Ira Street, Evans Bay, Frederick Street, Hataitai, Palm Grove, The Terrace and University at 33 kV; and
- Nairn Street at 11 kV.

Each zone substation is supplied from two separate 33 kV bus sections to provide N-1 security.

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Transmission Planning Report. WELL and Transpower have been investigating options for site diversity to improve CBD supply resilience. The preferred option is to move assets including one 110/33 kV transformer, 33 kV switchgear and associated protection, to a site near Central Park that would operate in parallel with the existing Central Park GXP. This is discussed further in Section 12.

[38] Wilton 33 kV ADMD peak demand excluding West Wind generation.

9.4.1.2 Wilton GXP

The peak demand on the Wilton GXP in 2023 was 40.1 MVA. Wilton supplies zone substations at Karori, Moore Street, Waikowhai Street each via double 33 kV circuits.

The Wilton 110 kV bus consists of three sections and provides supply diversity and resilience as each of the three Central Park circuits are terminated to an individual bus section.

Transpower has also undertaken a risk assessment of a loss of key assets at Wilton, such as the entire 220 kV or 110 kV bus structures and has developed concept plans for bypass arrangements that would allow it to restore supply within short timeframes, should such an event occur.

9.4.1.3 Kaiwharawhara GXP

The peak demand on the Kaiwharawhara GXP in 2023 was 25.4 MVA. The Kaiwharawhara GXP supplies the Kaiwharawhara zone substation directly from the 110/11 kV transformer LV circuit breakers.

Transpower has no planned works at Kaiwharawhara.

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Kaiwharawhara is forecast to change as shown in Figure 9-7. The subtransmission capacity constraints are plotted for comparison.

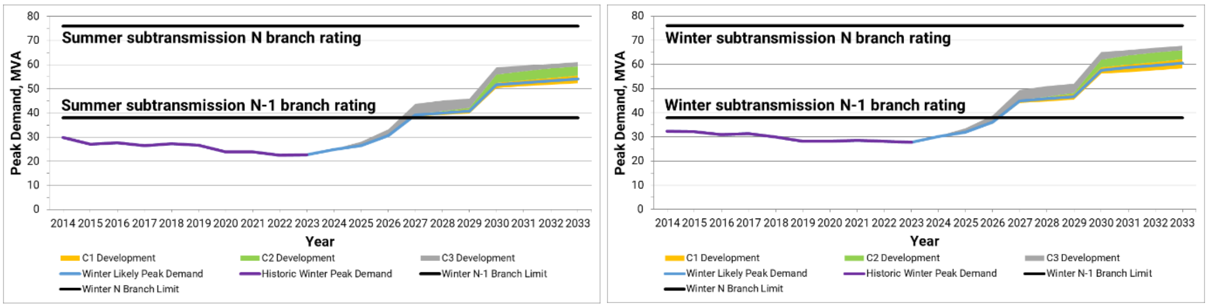


Figure 9-7 Kaiwharawhara Demand Forecast

The Kaiwharawhara demand is forecast to exceed the subtransmission N-1 capacity from 2027. In the short term this will be managed post-contingency. In the medium term, WELL plans to shift some load from Kaiwharawhara to Ngauranga. WELL will continue to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

9.4.2 Subtransmission Network Development Needs

This section describes the identified security of supply constraints and development needs for the Southern Area subtransmission network.

A supply capacity and demand overview of each zone substation is listed in Table 9-10.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)		Constraining Branch Component[39]	Peak Demand C1 (MVA)		Year Constraint Binding			ICP Counts as at 2023
		Existing	Post-upgrade		2023	2033	C1	C2	C3	
Existing Constraints										
Palm Grove	Winter	20.0	N/A	Transformer	24.1	38.0	Existing			10,535
	Summer	20.0	N/A	Transformer	16.4	29.9	2025	2025	2025	
Forecasted Constraints										
8 Ira Street	Winter	19.0	36.0	33kV Cable	16.2	35.4	2024	2024	2024	4,910
	Summer	15.0	36.0	33kV Cable	12.5	31.2	2024	2024	2024	
Frederick Street	Winter	30.0	N/A	Transformer	25.8	42.1	2024	2024	2024	7,274
	Summer	30.0	N/A	Transformer	22.0	38.3	2026	2025	2025	
Karori	Winter	20.0	N/A	33kV Cable	14.3	20.9	2032	2031	2027	6,152
	Summer	15.0	N/A	33kV Cable	9.0	14.7	-	2032	2028	
Moore Street	Winter	30.0	N/A	Transformer	19.0	30.7	2033	2027	2026	846
	Summer	30.0	N/A	Transformer	20.5	32.8	2030	2025	2025	
Nairn Street	Winter	22.0	N/A	11kV Incomer	21.4	29.1	2025	2024	2024	7,275
	Summer	22.0	N/A	11kV Incomer	15.2	21.0	-	2031	2029	
University	Winter	20.0	N/A	Transformer	17.6	22.4	2027	2025	2025	6,209
	Summer	20.0	N/A	Transformer	13.4	16.1	-	-	-	
Waikowhai Street	Winter	15.0	N/A	Transformer	13.5	16.8	2028	2028	2025	5,788
	Summer	15.0	N/A	Transformer	8.3	11.2	-	2048	2042	
Evans Bay	Winter	19.0	24.0	33kV Cable	12.6	23.8	2028	2027	2025	4,954
	Summer	15.0	24.0	33kV Cable	9.1	20.3	2027	2026	2025	
Not Constrained										
Hataitai	Winter	21.0	N/A	33kV Cable	15.8	19.2	-	2039	2037	6,910
	Summer	15.0	N/A	33kV Cable	10.0	13.2	-	2040	2037	
The Terrace	Winter	30.0	N/A	Transformer	22.9	28.1	-	2033	2029	1,736
	Summer	30.0	N/A	Transformer	22.5	29.2	-	2031	2028	

Table 9-10 Southern Area Zone Substation Capacities

At the subtransmission level, WELL's planning criterion is to maintain N-1 capacity down to the 11 kV incomer level based on equipment maximum continuous rating (MCR).[40]

A typical subtransmission circuit in the area is configured in the following manner:

- Cabling at 33 kV to the zone substation supply transformers. This consists of a double circuit arrangement terminating onto 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%;

[39] Subtransmission branch consists of incoming 33kV circuits, the 33/11kV transformer and the 11 kV incomer circuit breakers

[40] Maximum continuous rating (MCR) vs cyclic capacity: MCR is used for capacity planning to cover peak and cyclic rating (for a specified limited duration) is used for operations to cover short-term peak loading and contingencies.

- Zone substation 33 kV/11 kV supply transformers, with a continuous rating in the range of 20-30 MVA, fitted with oil circulation pumps and cooling fans if necessary to provide a higher cyclic rating; and

- 11 kV cabling from the 11 kV bushings of the transformers to the switchboard incomers, which can potentially constrain the subtransmission circuit rating if undersized, is also considered a component of the subtransmission circuit.

Subtransmission constraints can be quantified in terms of the duration of potential overload assessed against the security criteria using a load duration curve. Forecast constraints are quantified in terms of when the risk of overload is likely to occur based on the forecast peak demand for a given year.

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

9.4.2.1 8 Ira Street

The peak load supplied by 8 Ira Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-11 shows the seasonal constraint levels and the minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
8 Ira Street	Winter	20	16.2	0
	Summer	15	12.5	0

Table 9-11 Current 8 Ira Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at 8 Ira Street is forecast to change as shown in Figure 9-8. The subtransmission capacity constraints are plotted for comparison.

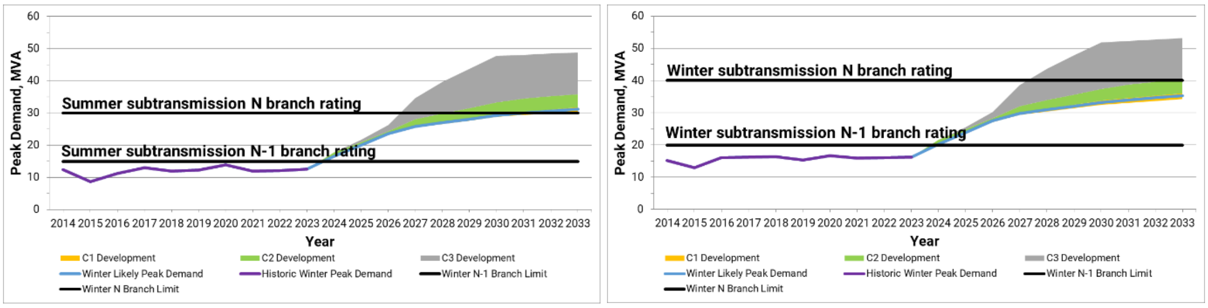


Figure 9-8 8 Ira Street Demand Forecast

The 8 Ira Street peak demand is forecast to exceed the summer and winter subtransmission N-1 capacity from 2024. The following works are proposed to resolve these constraints:

- Replace the 11 kV switchgear at Ira Street to allow additional feeders for strengthening 11 kV ties with Evans Bay, planned for 2025.

- Upgrade the gas-filled 33 kV cables from Evans Bay to 8 Ira Street, proposed for 2027.

- Upgrade the 8 Ira Street 33/11 kV transformers, proposed for 2030.

This stepwise approach to increasing the capacity at 8 Ira Street is preferred over the alternative options of offloading demand to Evans Bay or building a new zone substation, as it allows expenditure on capacity increases to be phased to match demand growth as it is realised.

9.4.2.2 Evans Bay

The peak demand supplied from Evans Bay is currently within the N-1 capacity of the subtransmission circuits. Table 9-12 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Evans Bay	Winter	19 .0	12.6	0
	Summer	15.0	9.1	0

Table 9-12 Current Evans Bay Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Evans Bay is forecast to change as shown in Figure 9-9. The subtransmission capacity constraints are plotted for comparison.

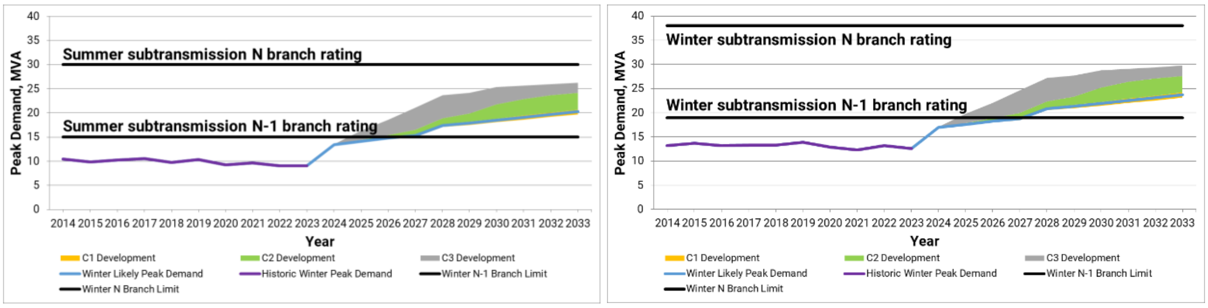


Figure 9-9 Evans Bay Demand Forecast

WELL has initiated a project, scheduled for completion in 2024, to:

- Install a 33 kV bus at Evans Bay to increase system security into the Miramar Peninsula; and
- Replace the existing 33/11 kV transformers due to their condition and future capacity requirements.

WELL proposes to replace the 33kV cables from Central Park to Evans Bay, expected to be required in 2027. An alternative option would be to offload the substation to neighbouring zone substations, however, these substations are approaching their own capacity limits, so this option is not preferred.

9.4.2.3 Frederick Street

The peak demand supplied by Frederick Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-13 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Frederick Street	Winter	30.0	25.8	0
	Summer	30.0	22.0	0

Table 9-13 Current Frederick Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Frederick Street is forecast to change as shown in Figure 9-10. The subtransmission capacity constraints are plotted for comparison.

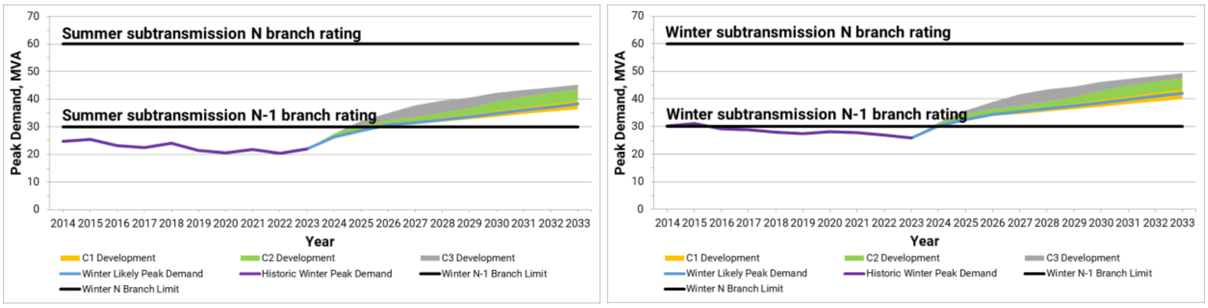


Figure 9-10 Frederick Street Demand Forecast

The Frederick Street winter peak demand is forecast to exceed the transformer N-1 capacity from 2024. The summer peak demand is forecast to exceed the transformer N-1 capacity from 2026.

The preferred option to manage the load at Frederick Street zone substation is to build a new zone substation at Newtown by approximately 2026. WELL will manage the Frederick Street load operationally by shifting load to adjacent zone substations to relieve overloads until this occurs.

An alternative option would be to upgrade the 33kV/11kV transformers and 11kV switchboard at Frederick Street. This option is not preferred as the Newtown substation is required for other projects, so represents a more efficient long-term investment.

9.4.2.4 Hataitai

The peak demand supplied from Hataitai is currently within the N-1 capacity of the subtransmission circuits. Table 9-14 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Hataitai	Winter	21.0	15.8	0
	Summer	15.0	10.0	0

Table 9-14 Current Hataitai Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Hataitai is forecast to change as shown in Figure 9-11. The subtransmission capacity constraints are plotted for comparison.

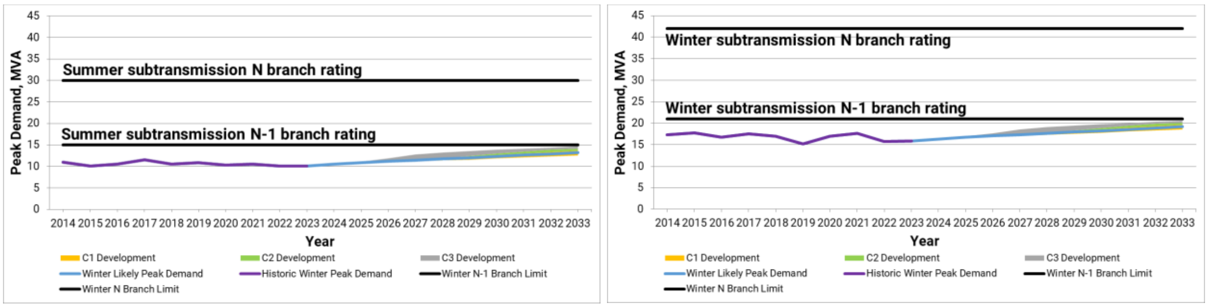


Figure 9-11 Hataitai Demand Forecast

The Hataitai peak demand is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this Plan.

9.4.2.5 Karori

The peak demand supplied from Karori is currently within the N-1 capacity of the subtransmission circuits. Table 9-15 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Karori	Winter	20.0	14.3	0
	Summer	15.0	9.0	0

Table 9-15 Current Karori Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Karori is forecast to change as shown in Figure 9-12. The subtransmission capacity constraints are plotted for comparison.

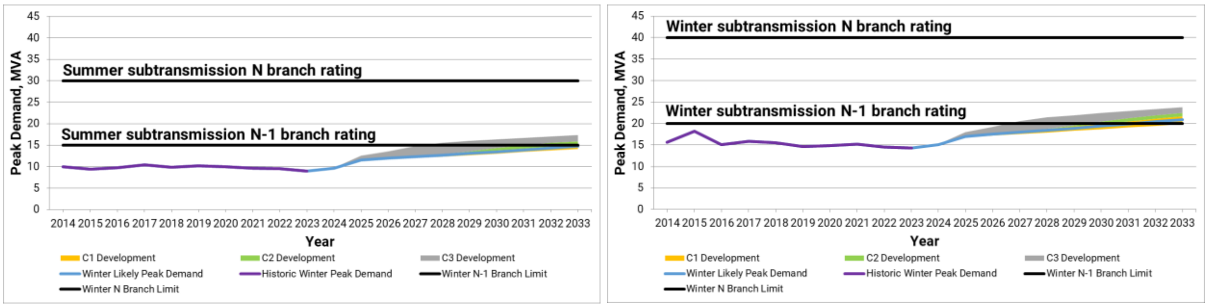


Figure 9-12 Karori Demand Forecast

The Karori peak demand is forecast to exceed the subtransmission N-1 capacity from 2031. These gas-filled cables are expected to be replaced due to Health-Criticality by 2029, with the replacement cables to be sized to suit the long-term load forecast. WELL will continue to monitor the load growth and will investigate further options to mitigate the system constraints as possible step load growth gets confirmed.

9.4.2.6 Moore Street

The peak demand supplied from Moore Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-16 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Moore Street	Winter	30.0	19.0	0
	Summer	30.0	20.5	0

Table 9-16 Current Moore Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Moore Street is forecast to change as shown in Figure 9-13. The subtransmission capacity constraints are plotted for comparison.

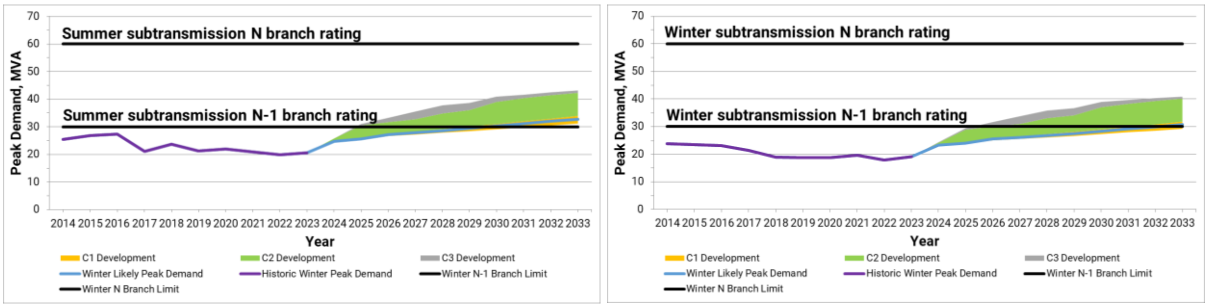


Figure 9-13 Moore Street Demand Forecast

There is potential for significant customer growth at Moore Street which could bring the load above the N-1 limits. WELL will continue to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

9.4.2.7 Nairn Street

The peak demand supplied from Nairn Street currently exceeds the N-1 rating of the 11 kV incomer cables. Table 9-17 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Nairn Street	Winter	22.0	21.4	0.1
	Summer	22.0	15.2	0

Table 9-17 Current Nairn Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Nairn Street is forecast to change as shown in Figure 9-14. The subtransmission capacity constraints are plotted for comparison.

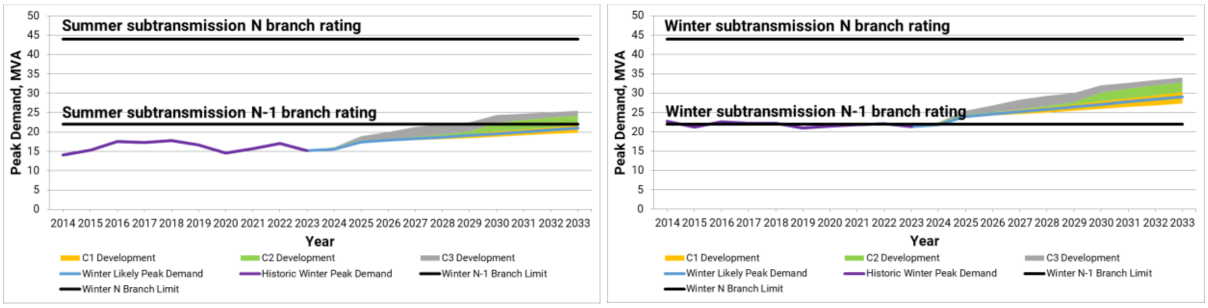


Figure 9-14 Nairn Street Demand Forecast

WELL continues to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed. In the medium term, load will be shifted from Nairn Street to a new zone substation to be developed in Newtown.

An alternative option would be to upgrade the 11kV switchboard at Nairn Street. This option is not preferred as the Newtown substation is required for other projects, so represents a more efficient long-term investment.

9.4.2.8 Palm Grove

The winter peak demand at Palm Grove currently exceeds the N-1 capacity of the transformers as shown in Table 9-18.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Palm Grove	Winter	20.0	24.1	4.1
	Summer	20.0	16.4	0

Table 9-18 Current Palm Grove Subtransmission Constraints

Based on the growth scenarios and the development accounted for within the planning period, the load at Palm Grove is forecast to grow as shown in Figure 9-15.

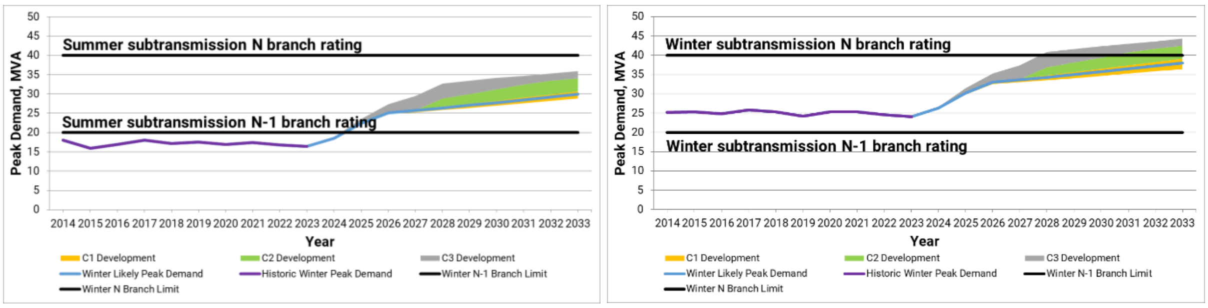


Figure 9-15 Palm Grove Demand Forecast

The preferred option to manage the load at Palm Grove zone substation is to build a new zone substation at Newtown by approximately 2026. WELL will manage the Palm Grove load operationally by shifting load to adjacent zone substations to relieve overloads until this occurs.

An alternative option would be to upgrade the 33 kV/11 kV transformers and 11 kV switchboard at Palm Grove. This option is not preferred as the Newtown substation is required for other projects, so represents a more efficient long-term investment.

9.4.2.9 The Terrace

The peak demand at The Terrace is currently within the N-1 capacity of the subtransmission circuits as shown in Table 9-19.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
The Terrace	Winter	30.0	22.9	0
	Summer	30.0	22.5	0

Table 9-19 Current The Terrace Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at The Terrace is forecast to change as shown in Figure 9-16. The subtransmission capacity constraints are plotted for comparison.

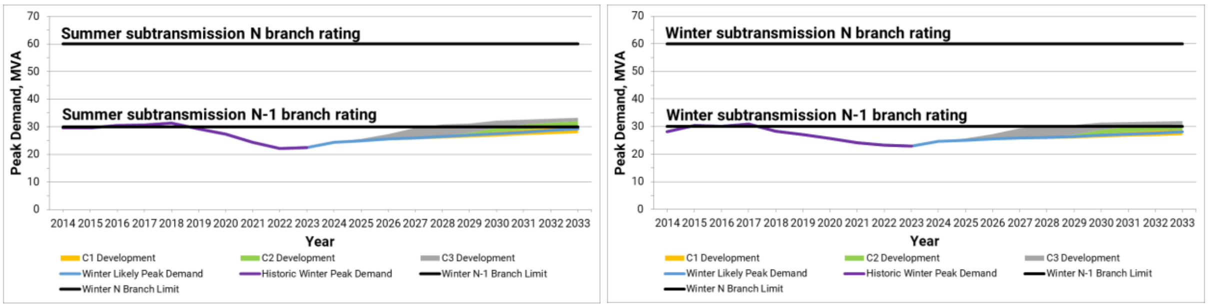


Figure 9-16 The Terrace Demand Forecast

The Terrace peak demand is forecast to remain within the winter and summer subtransmission N-1 capacity for the duration of this Plan.

9.4.2.10 University

The peak demand supplied from University is currently within the N-1 capacity of the subtransmission circuits. Table 9-20 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
University	Winter	20.0	17.6	0
	Summer	20.0	13.4	0

Table 9-20 Current University Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at University is forecast to change as shown in Figure 9-17. The subtransmission capacity constraints are plotted for comparison.

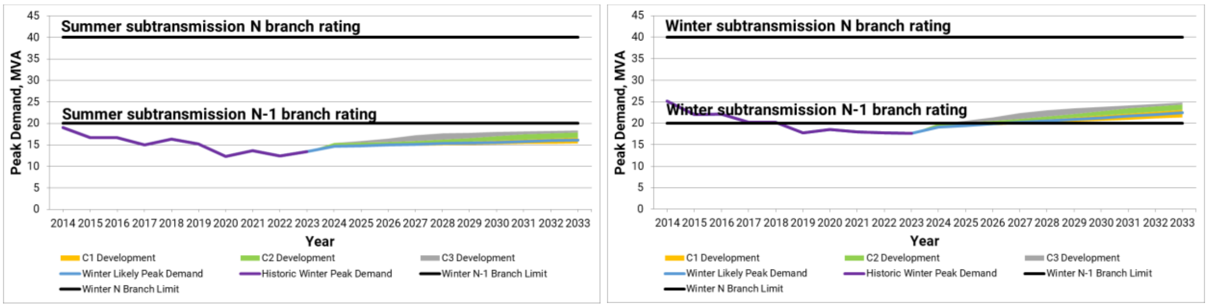


Figure 9-17 University Demand Forecast

The University winter peak demand is forecast to exceed the winter subtransmission N-1 capacity by 2027.

WELL will continue to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

9.4.2.11 Waikowhai Street

The peak demand supplied from Waikowhai Street is currently within the N-1 capacity of the subtransmission circuits. Table 9-21 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Waikowhai Street	Winter	15.0	13.5	0
	Summer	15.0	8.3	0

Table 9-21 Current Waikowhai Street Subtransmission Constraints

Based on the estimated growth scenarios and step change growth accounted for within the planning period, the load at Waikowhai Street is forecast to change as shown in Figure 9-18. The subtransmission capacity constraints are plotted for comparison.

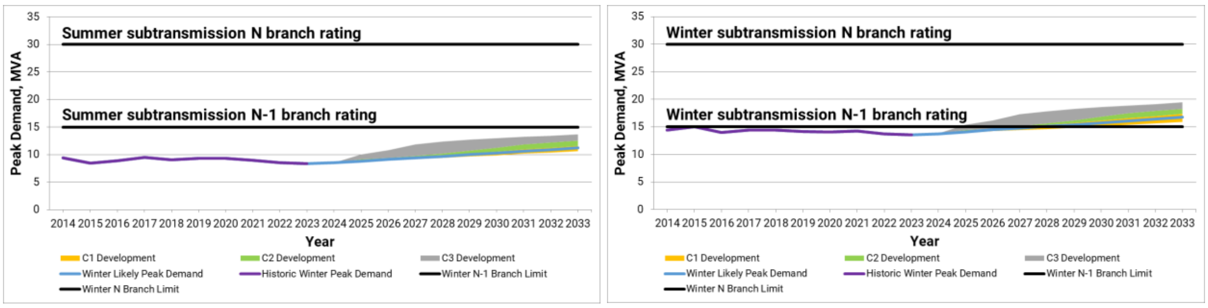


Figure 9-18 Waikowhai Street Demand Forecast

The Waikowhai Street winter peak demand is forecast to exceed the winter subtransmission N-1 capacity by 2028. These gas-filled cables are expected to be replaced by 2031. WELL will manage the Waikowhai Street load operationally by shifting load to adjacent zone substations to relieve overloads until this occurs.

9.4.3 Distribution Network Development Needs

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 interdependencies and their effect on the Wellington CBD network as a whole.

Each zone substation supplies the respective 11 kV distribution network, with most zone substations having interconnectivity via switched open points to adjacent zones. The most critical distribution level issues are those associated with:

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

Table 9-22 shows where the applicable security criteria for normal operating conditions are exceeded, based on forecast demand growth and confirmed step load changes. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder is the priority level of the planning and investment requirements.

Feeder	Security Criteria	Present Loading	+5 years Loading C1	+5 years Loading C2	+5 years Loading C3	Feeder ICP Count	Priority
Existing Constraints							
Frederick Street 13/14	50%	64.9%	91.9%	97.7%	114.6%	3,177	High
Karori 3/6	50%	71.2%	93.6%	94.9%	104.0%	3,783	Medium
Kaiwharawhara 6/7/9/10	75%	92.7%	102.4%	106.2%	133.6%	3,043	High
Nairn Street 11/13	50%	72.2%	86.0%	86.8%	102.3%	1,473	Medium
Evans Bay 2/4	50%	63.0%	90.4%	91.3%	110.7%	2,970	High
Palm Grove 2/3/6	67%	95.3%	109.6%	115.9%	137.9%	4,533	High
Moore Street 1/2	50%	53.1%	67.3%	68.0%	76.8%	442	Medium
University 8/10	50%	63.5%	71.4%	71.8%	76.8%	2,314	Medium
Forecasted Constraints							
Frederick Street 2	67%	<67%	78.2%	74.9%	82.4%	802	Medium
Frederick Street 3/4/5/8	75%	<75%	79.6%	87.5%	93.2%	3,233	High
Moore Street 1/2	50%	53.1%	67.3%	68.0%	76.8%	442	Medium
Nairn Street 8/12	50%	<50%	63.8%	68.8%	71.1%	56	Low
University 12	67%	<67%	69.5%	70.0%	75.2%	1,335	Low
Ira Street 4	67%	<67%	118.6%	135.1%	147.9%	971	Medium
Ira Street 6	67%	<67%	74.1%	75.0%	90.3%	1,166	Medium
Ira Street 8/9	50%	<67%	108.3%	127.4%	207.3%	456	High
Ira Street 11	67%	<67%	<67%	<67%	71.9%	744	Medium
Evans Bay 10/11	50%	<50%	50.7%	74.%%	88.7%	1,544	Medium
Palm Grove 8/10/12	67%	<67%	78.6%	80.1%	92.7%	5,242	High

Table 9-22 Distribution Level Issues

Feeder protection settings are typically set for protection of the feeder breaker and an allowable short-time overload of the cables. The sudden loss of a single feeder in a meshed ring may result in the transfer of load to the remaining feeders, and protection settings are designed to avoid a trip of the feeder protection relays at the zone substation when this occurs. The loading figures are worst-case because in most scenarios an isolated 11kV feeder section will also disconnect load which will reduce the contingency load transferred to the remaining feeders. The network solution to fix a highly loaded feeder is unlikely to require the full length of the feeder to be upgraded, and it may just need a tactical upgrade of a short length or a reconfiguration of feeder open points.

Table 9-23 shows the results of the contingency analysis performed on the ring feeders in the Southern Area which currently exceeds the security criteria. Overloading feeder segments for each contingency scenario are shown. The contingency loading calculation is based on the current peak demand for each feeder recorded for 2023.

Feeder	Feeder out of service	Overloaded in-service feeder(s)	Loading on the in-service feeder sections
Current			
Evans Bay 02/04	EVA CB02 Out	EVA CB04	118.1%
	EVA CB04 Out	EVA CB02	119.2%
Frederick Street 13/14	FRE CB13 Out	FRE CB14	116.0%
	FRE CB14 Out	FRE CB13	132.0%
Ira Street 08/09	IRA CB08 Out	IRA CB09	105.4%
Karori 03/06	KAR CB03 Out	KAR CB06	148.7%
	KAR CB06 Out	KAR CB03	132.1%
Palm Grove 02/03/06	PAL CB02 Out	PAL CB06	128.2%
Palm Grove 08/10/12	Any One of the Three	Mid-section of Palm Grove 08/10/12	113.5%
University 08/10	UNI CB08 Out	UNI CB10	118.6%
	UNI CB10 Out	UNI CB08	117.7%
Within 5 Years			
Evans Bay 02/04	EVA CB02 Out	EVA CB04	163.5%
	EVA CB04 Out	EVA CB02	193.9%
Frederick Street 3/4/5/8	FRE CB03 Out	FRE CB08	118.6%
	FRE CB04 Out	FRE CB08	115.1%
	FRE CB05 Out	FRE CB08	105.9%
	FRE CB08 Out	FRE CB04	109.5%
Frederick Street 13/14	FRE CB13 Out	FRE CB14	139.5%
	FRE CB14 Out	FRE CB13	160.9%
Ira Street 08/09	IRA CB08 Out	IRA CB09	266.7%
	IRA CB09 Out	IRA CB08	186%
Karori 03/06	KAR CB03 Out	KAR CB06	184.1%
	KAR CB06 Out	KAR CB03	163.2%
Palm Grove 02/03/06	PAL CB02 Out	PAL CB06	186.2%
Palm Grove 08/10/12	CB08 or CB10	PAL CB12	137.2%
University 08/10	UNI CB08 Out	UNI CB10	131.7%
	UNI CB10 Out	UNI CB08	130.6%

Table 9-23 Ring Feeder Contingency Analysis

WELL is aware of a number of possible future step load changes identified through customer connection requests, developments detailed in the local council District Plans and through consultation with city councils, developers, and large customers. A number of property developers and businesses have also flagged developments that may create new loads on the network.

The actual outcomes and impacts of these possible future step-change demands are uncertain, difficult to estimate, and have not been included in the assessment above. WELL is aware some steps loads are compensated by load being reduced in other areas. WELL will continue to monitor progress with these possible step change demands and develop timely solutions to resolve any network issues arising from the step load change demands as they are confirmed.

9.4.4 Summary of Network Development Plan

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

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

9.4.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to evaluate non-network solutions, discussed in Section 9.1.9, to defer investment.

9.4.4.2 Projects for 2024/25

Table 9-24 lists projects currently underway or planned to start over the next 12 months.

Project	Description
Evans Bay 33 kV Bus	Construction of a 33 kV bus at Evans Bay substation. Installation is to be completed during 2024.

Table 9-24 Southern Area Projects for 2024/25

9.4.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 9-25. This information is an extract from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example, some subtransmission constraints can be solved through 11 kV distribution level configuration change or managed operationally by shifting load to adjacent zone substations to relieve overloads.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Project	Description	Constraint Relieved	Target Completion	Investment
Subtransmission Constraints				
Evans Bay 33kV Cable Replacement	Replace existing gas cables with 3x1C 1000mm² Al XLPE.	Evans Bay 33kV ring	2027	$15M
Newtown Zone Substation	Build a new zone substation in the vicinity of Wellington Hospital. Additional 11kV trenching to access feeders from neighbouring substations.	Palm Grove transformers, Palm Grove 2/3/6, Frederick Street 13/14, Nairn Street 8/12, Hataitai 7/9/10	2026	$57M
Ira Street 33kV Gas Cable Replacement	Replace existing gas cables to Ira Street by installing 3x 1c 1000mm² between Evans Bay and Ira Street.	Ira Street 33kV cables	2027	$15M
Ira Street Transformer Upgrade	Upgrade transformers to 2 x 36 MVA.	Ira Street transformers	2030	$11M
Ira Street Switchboard Replacement	Replace 11 kV switchboard	Providing additional feeders for resolving distribution constraints.	2025	$6.0M
Waikowhai Street 33kV Gas Cable Replacement	Replace existing gas cables to Waikowhai Street	Waikowhai Street 33kV cables	2031	$14M
Distribution Constraints				
Ira Street 8/9	Run 11 kV cables between 8 Ira Street and Evans Bay. Establish 11 kV switching station at Wellington International Airport.	Ira Street 8/9	2025	$28M
Kaiwharawhara Ring 2	Offload Abattoirs Road to Ngauranga.	Kaiwharawhara 6/7/9/10	2028	$5.5M
Moore Street 1/2 reconfiguration	Reconfigure and establish Moore Street 11.	Moore Street 1/2, University 8/10	2028	$0.2M
New Ira Street 11kV feeders	Run two circuits from Ira Street to 127 Wexford Road. Upgrade cables between 127 Wexford Road and 19 Tauhinu Road.	Evans Bay 2/4	2028	$15M
Frederick Street 11kV reinforcement	Run new radial feeder to 176 Wakefield Street.	Frederick Street 3/4/5/8	2028	$9.5M
New Karori 11kV feeder	Run new feeder to Ranelagh Street. Establish a switching station.	Karori 3/6	2026	$10M
New Palm Grove 11kV Feeder	Run two circuits from Palm Grove to the Parade Switch House. Offload Palm Grove 8/10/12, Nairn Street 11/13 and Nairn Street 14.	Palm Grove 8/10/12	2027	$15M
University 1/4/6	Establish Terrace 7 as a radial feeder and offload University 1/4/6.	University 1/4/6	2027	$0.2M
Moore Street 12/14	Offload feeder.	Moore Street 12/14, University 8/10	2025	$0.1M
Nairn Street 1/2/3/6	Offload feeder.	Nairn Street 1/2/3/6	2036	$0.2M

Table 9-25 Southern Area Development Summary

9.5 Northwestern Area NDRP

This section provides a summary of the Northwestern Area NDRP.

9.5.1 GXP Development Plans

The Northwestern Area is supplied from two GXPs, Takapu Road and Pauatahanui. Transpower owns the supply transformers at the GXPs. The transformer capacity and the peak system demand are set out in Table 9-26. The forecast in Table 9-26 considers only committed developments.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2023	2033
Takapu Road 33 kV	2x90	111 / 116	87	147
Pauatahanui 33 kV	2x20	22 / 24	16	29

Table 9-26 Northwestern Area GXP Capacities

Many of the investment needs identified at Transpower GXPs have been detailed in Transpower's Transmission Planning Report.

The development needs at each GXP are discussed further below.

9.5.1.1 Takapu Road

The Takapu Road GXP comprises two parallel 110/33 kV transformers each nominally rated at 90 MVA with a winter N-1 cyclic capacity of 116 MVA. The maximum demand on the Takapu Road GXP in 2023 was 87 MVA. Takapu Road supplies zone substations at Waitangirua, Porirua, Kenepuru, Tawa, Ngauranga and Johnsonville each via double 33 kV circuits. The Ngauranga subtransmission circuits from Takapu Road GXP are on a 110 kV-rated double-circuit tower line. The line is owned and maintained by Transpower.

The Takapu Road peak demand is forecast to be at the subtransmission N-1 capacity at the end of the next ten-year period with confirmed and highly likely step load growth. WELL is working with Transpower to:

- Increase the transformer capacity at Takapu Road, and
- Allow for an additional connection point to the future Grenada zone substation.

9.5.1.2 Pauatahanui

The Pauatahanui GXP is supplied from the Takapu Road GXP via two 110 kV circuits. Pauatahanui GXP comprises two parallel 110/33 kV transformers rated at 20 MVA each, with a winter cyclic N-1 capacity of 24 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 asset renewal or replacement will be required within the next 5-10 years. Potential housing and small industrial development in Plimmerton (Porirua City's Northern Growth Area) may add up to 7 MVA to the peak demand over a 15-year period, which may cause Pauatahanui GXP loading to exceed the N-1 rating of existing transformers. Furthermore, the connection of additional traction load in the area risks compromising the quality of supply in the long term.

WELL is presently working with Transpower regarding options for mitigating the risk posed by flooding at the Pauatahanui site.

9.5.2 Subtransmission Network Development Needs

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

The Northwestern network consists of twelve 33 kV subtransmission circuits supplying eight zone substations. Each zone substation supplies the 11 kV distribution network with interconnectivity via switched open points to adjacent zones. All 11 kV feeders are radial from the zone substations except for the meshed ring feeders supplying the Porirua CBD and Titahi Bay substation. The load summary of each zone substation is listed in Table 9-27.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)		Constraining Branch Component[41]	Peak Demand C1 (MVA)		Year Constraint Binding			ICP Counts as at 2023
		Existing	Post - upgrade		2023	2033	C1	C2	C3	
Existing Constraints										
Johnsonville	Winter	16.0	N/A	33kV Cable	20.3	30.0	Existing			8,992
	Summer	11.5	N/A	33kV Cable	12.8	20.7	Existing			
Ngauranga	Winter	10.0	36.0	Transformer	11.1	21.5	Existing			4,513
	Summer	10.0	36.0	Transformer	7.6	17.1	2025	2025	2025	
Mana	Winter	7.0	14.0	11kV Intertie	9.0	12.4	Existing			4,721
	Summer	7.0	14.0	11kV Intertie	6.1	9.1	2027	2027	2026	
Plimmerton	Winter	7.0	22.0	11kV Intertie	8.4	18.2	Existing			2,411
	Summer	7.0	22.0	11kV Intertie	5.5	15.0	2025	2025	2025	
Porirua	Winter	16.0	36.0	Transformer	21.7	39.4	Existing			3,974
	Summer	14.2	36.0	33kV Cable	16.0	32.1	Existing			
Forecasted Constraints										
Kenepuru	Winter	18.4	N/A	33kV Cable	11.2	20.8	2030	2030	2027	2,370
	Summer	13.7	N/A	33kV Cable	9.0	18.1	2027	2027	2025	
Tawa	Winter	16.0	36.0	Transformer	14.5	25.7	2024	2024	2024	5,419
	Summer	14.6	36.0	33kV Cable	10.0	20.5	2026	2026	2025	
Waitangirua	Winter	16.0	21.1	Transformer	13.9	21.1	2025	2025	2025	6,181
	Summer	15.2	15.2	33kV Cable	9.0	15.9	2032	2030	2027	

Table 9-27 Northwestern Area Zone Substation Capacities

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

[41] Subtransmission branch consists of incoming 33kV circuits, the 33/11kV transformer and the 11 kV incomer circuit breakers

Subtransmission constraints can be quantified in terms of duration of risk and assessed against the security criteria in Table 9-1, using a load duration curve. Forecast 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.

9.5.2.1 Johnsonville

The peak demand supplied by Johnsonville currently exceeds the N-1 capacity of the subtransmission circuits. Operational risk is currently managed by load control and transfer to HV feeders from other zone substations. Table 9-28 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Subtransmission N-1 Constraining N-1 branch rating (MVA)rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Johnsonville	Winter	16.0	20.3	4.3
	Summer	11.5	12.8	2.1

Table 9-28 Current Johnsonville Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Johnsonville is forecast to grow as shown in Figure 9-19.

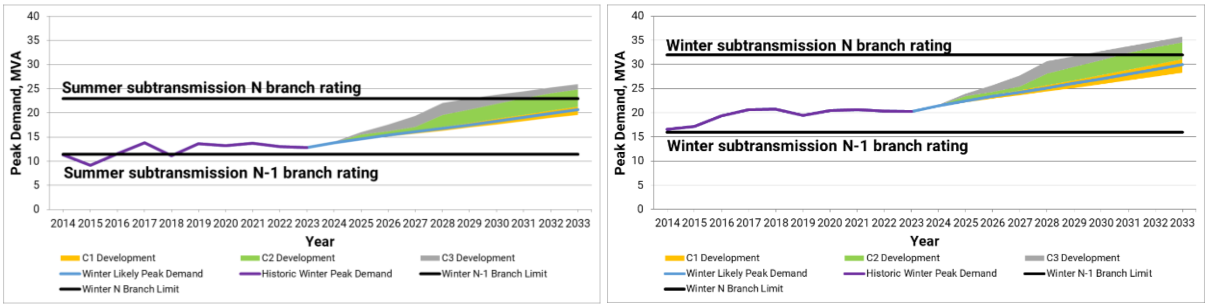


Figure 9-19 Johnsonville Demand Forecast

WELL intends to transfer some load from Johnsonville to a proposed new zone substation at Grenada, currently planned for 2028. Alternative options to this solution include increasing the capacity at Johnsonville through replacement of the 33 kV cables and transformers, however the Grenada substation is preferred as it offers capacity and security benefits to Tawa and Ngauranga zone substations in addition to Johnsonville, and is therefore a cost-effective solution.

9.5.2.2 Kenepuru

Maximum demand at Kenepuru is within available N-1 subtransmission capacity. Table 9-29 shows the seasonal constraint levels and the minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Kenepuru	Winter	18.3	11.2	0
	Summer	13.7	9	0

Table 9-29 Current Kenepuru Subtransmission Constraints

Forecast load growth will come from a new residential subdivision, and industrial load from a factory expanding operations. Figure 9-20 shows the forecast demand for Kenepuru zone substation.

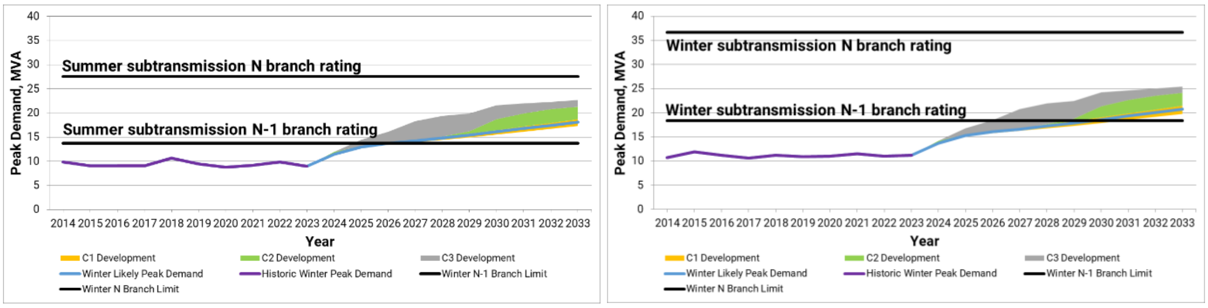


Figure 9-20 Kenepuru Demand Forecast

The Kenepuru summer peak demand is forecast to exceed the subtransmission N-1 capacity from 2026. WELL will continue to monitor the load growth and will investigate options to mitigate system constraints as possible step load growth gets confirmed.

9.5.2.3 Ngauranga

The winter peak demand supplied by Ngauranga currently exceeds the N-1 capacity of the subtransmission circuits. Operational risk is currently managed by load control and transfer to HV feeders from other zone substations. Table 9-30 shows the seasonal constraint levels and the minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Ngauranga	Winter	10.0	11.1	1.1
	Summer	10.0	7.6	0

Table 9-30 Current Ngauranga Subtransmission Constraints

Additional demand will result from transferring of the primary supply for Abattoirs Road from Kaiwharawhara to Ngauranga in 2025.

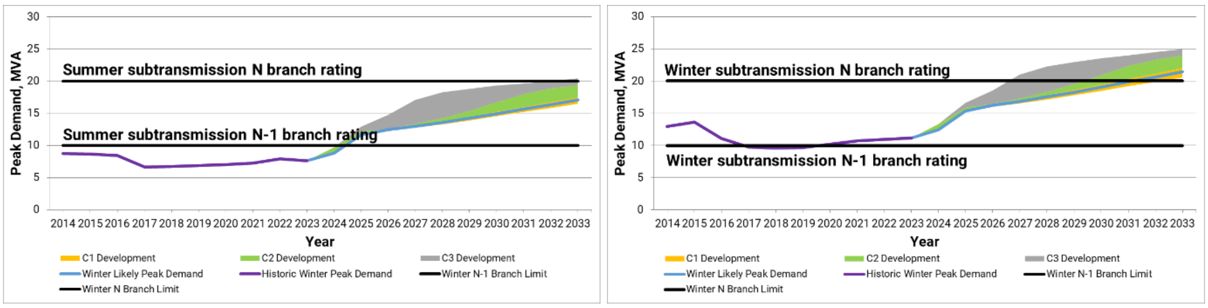


Figure 9-21 Ngauranga Demand Forecast

WELL plans to resolve this issue by replacing the Ngauranga transformers with higher-capacity units in 2026. This aligns with the transformers approaching end of life, so replacement of this equipment is a cost-effective solution. This will provide sufficient capacity for the foreseeable future. In the interim, WELL plans to manage supply security operationally by shifting load to adjacent zone substations to relieve overloads.

In the long-term, WELL also plans to shift some load to a new zone substation in Grenada from 2029.

9.5.2.4 Mana

The Mana zone substation is supplied via a single subtransmission circuit (i.e. a single 33/11 kV transformer and 33kV circuit from Pauatahanui GXP). The Mana zone substation peak demand is below the capacity of this single subtransmission circuit.

The 11 kV buses of the Mana and Plimmerton zone substations are connected via an 11 kV bus tie cable to provide up to 7 MVA backfeed capacity between the two zone substations. When the single 33 kV circuit supplying Mana zone substation is out of service, the amount of load at Mana that can be supplied from the 11 kV bus-tie to Plimmerton zone substation will be limited to the lower of:

- The capacity of the 11 kV bus tie cable between Mana and Plimmerton (7 MVA), or
- Ensuring the combined Mana and Plimmerton load does not exceed the capacity of the single subtransmission circuit at Plimmerton (16 MVA).

This may require transferring Mana load to adjacent zone substations, as summarised in Table 9-31.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Mana	Winter	7.0	9.0	2.0
	Summer	7.0	6.1	0

Table 9-31 Current Mana Subtransmission Constraints

Figure 9-22 shows the forecast demand for Mana zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

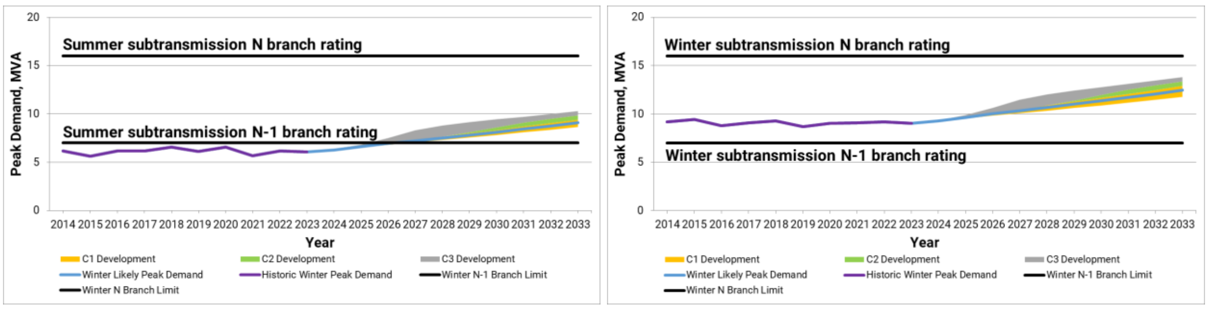


Figure 9-22 Mana Demand Forecast

In the short-term, WELL can move load between Mana, Plimmerton, and Waitangirua, to manage the demand. WELL plans to upgrade the Mana-Plimmerton 11 kV tie in 2027.

9.5.2.5 Plimmerton

The Plimmerton zone substation is supplied via a single subtransmission circuit (i.e., a single 33/11 kV transformer and 33 kV circuit from Pauatahanui GXP). The Plimmerton zone substation demand is below the capacity of this single subtransmission circuit.

The 11 kV buses of Mana and Plimmerton zone substations are connected via an 11 kV bus tie cable to provide up to 7 MVA backfeed capacity between the two zone substations. When the single 33 kV circuit supplying Plimmerton zone substation is out of service, the amount of load at Plimmerton zone substation that can be supplied from the 11 kV bus-tie to Mana zone substation will be limited to the lower of:

- The capacity of the 11 kV bus tie cable between Mana and Plimmerton (7 MVA), or
- Ensuring the combined Mana and Plimmerton load does not exceed the capacity of the single subtransmission circuit at Mana (16 MVA).

This may require transferring some load to other zone substations, as summarised in Table 9-32.

Circuit	Season	Maximum Mana-Plimmerton Bus-tie capacity (MVA	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Plimmerton	Winter	7.0	8.4	1.4
	Summer	7.0	5.5	0

Table 9-32 Current Plimmerton Subtransmission Constraints

Figure 9-23 shows the forecast demand for Plimmerton zone substation based on the estimated growth scenarios and development within the planning period. The subtransmission capacity constraints are plotted for comparison.

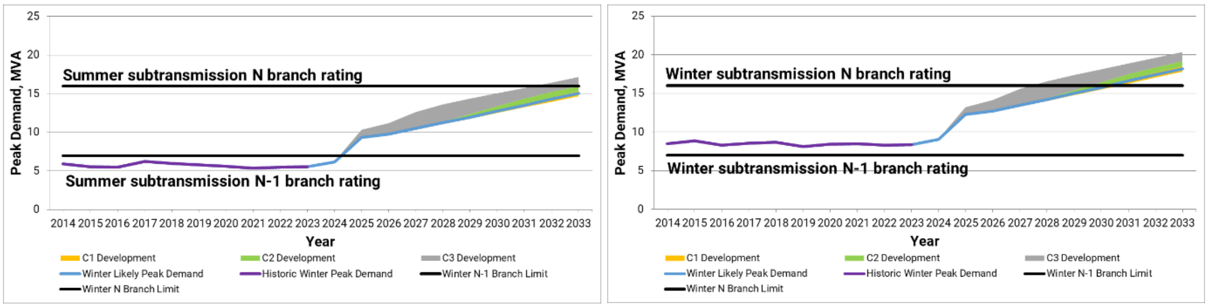


Figure 9-23 Plimmerton Demand Forecast

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 industrial development north of Plimmerton proceeds. The new development will also impact the network security and available capacity at Mana zone substation and its 11 kV feeders. Further load increases will result from a significant electrified public transport upgrade project planned for the area.

WELL plans to upgrade the Pauatahanui-Plimmerton and Pauatahanui-Mana 33 kV lines and connect the two lines to a new 33 kV bus at a new zone substation north of Plimmerton in 2027. The existing single transformer at Plimmerton will be replaced by two larger transformers at the new substation. This option is preferred over redeveloping the existing Plimmerton site due to the risk posed by the geotechnical stability of the hill behind the substation.

9.5.2.6 Porirua

The peak demand supplied at Porirua exceeds the N-1 subtransmission branch ratings for both winter and summer periods. Following a fault on the subtransmission system, load is off-loaded from Porirua to nearby alternative zone substations. Table 9-33 shows the seasonal constraint levels and the minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Porirua	Winter	16.0	21.7	5.7
	Summer	14.2	16	1.8

Table 9-33 Current Porirua Subtransmission Constraints

The risk of these constraints is dependent on planned step change demands due to the redevelopment of the Porirua city centre, continuing residential growth in the Aotea area, and the proposed Eastern Porirua Regeneration project. 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 9-24.

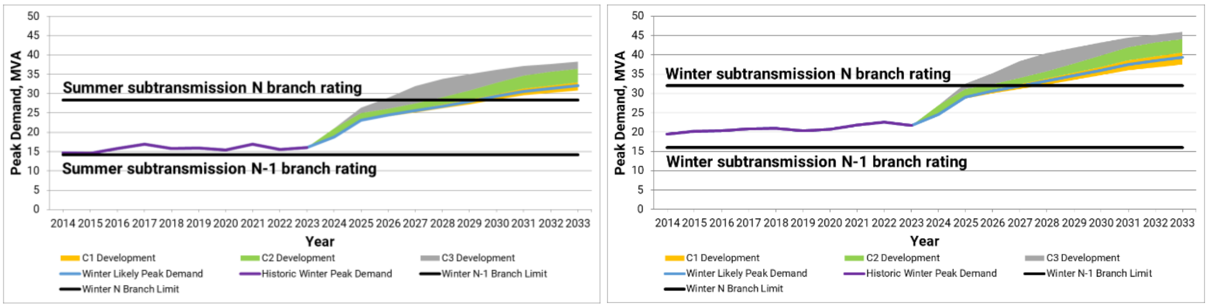


Figure 9-24 Porirua Demand Forecast

WELL plans to upgrade Porirua zone substation, commencing in 2025, including replacing the transformers with higher capacity units and replacing the subtransmission circuits, to resolve this issue. There is insufficient capacity at neighbouring zone substations to allow an alternative option of offloading the substation through the 11 kV network. WELL will manage supply security operationally by shifting load to adjacent zone substations to relieve overloads until the substation upgrade.

9.5.2.7 Tawa

The peak demand supplied from Tawa is currently within the N-1 capacity of the subtransmission circuits. Table 9-34 shows the seasonal constraint levels and the minimum offload requirements.

Circuit	Season	Constraining N-1 branch rating (MVA)	Peak Demand @ 2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Tawa	Winter	16.0	14.5	0
	Summer	14.4	10	0

Table 9-34 Current Tawa Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the load at Tawa is forecast to grow as shown in Figure 9-25.

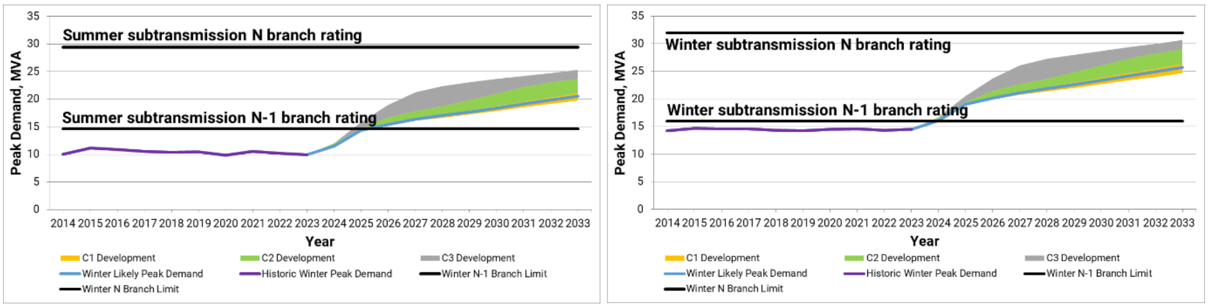


Figure 9-25 Tawa Demand Forecast

The winter peak demand is forecast to exceed the subtransmission N-1 capacity from 2024. Significant load growth is expected from public transport electrification upgrades in the area, with further growth resulting from the Grenada North industrial area and new residential developments in Grenada. The preferred option for resolving this constraint is replacement of the Tawa fluid-filled subtransmission cables and transformers in 2026. This aligns with the transformers and cables approaching end of life, so replacement of this equipment is a cost-effective solution.

9.5.2.8 Waitangirua

The peak demand supplied by Waitangirua is currently within the N-1 branch rating of the subtransmission circuits. Table 9-35 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Waitangirua	Winter	16.0	13.9	0
	Summer	15.2	9	0

Table 9-35 Current Waitangirua Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Waitangirua is forecast to grow as show in Figure 9-26. Without action, the peak demand will exceed the N-1 subtransmission capacity from 2025. This will also reduce the capacity available to backup adjacent zone substations. Growth in the Waitangirua load is expected to come from residential developments in the Whitby area and the proposed Eastern Porirua Regeneration project.

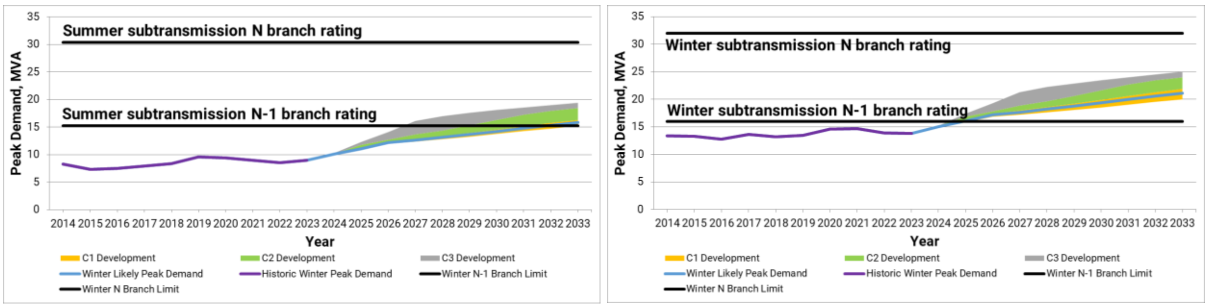


Figure 9-26 Waitangirua Demand Forecast

WELL will continue monitoring load growth and manage the overloading risk through operational control by shifting load to adjacent zone substations to relieve overloads. The transformers are currently proposed to be replaced with higher-capacity units in 2030.

9.5.3 Distribution Level Development Needs

The most critical distribution level issues are those associated with:

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

Table 9-36 shows where the applicable security criteria for the feeder configurations are exceeded, based on forecast demand growth and confirmed step load changes, and an estimation of when the constraints bind. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder is the priority level of the planning and investment requirements.

Feeder	Security Criteria	Present Loading	+5 years Loading C1	+5 years Loading C2	+5 years Loading C3	Feeder ICP Count	Priority
Existing Constraints							
Johnsonville 11	67%	84.9%	102.2%	103.4%	109.9%	1,191	High
Johnsonville 12	67%	67.7%	86.2%	87.9%	96.5%	1,358	Medium
Johnsonville 6	67%	71.8%	93.4%	95.1%	103.7%	1,870	High
Ngauranga 4	67%	73.4%	106%	107.5%	136.8%	1,782	Medium
Tawa 11	67%	68.8%	104.1%	104.7%	121.2%	660	High
Waitangirua 5	67%	79.8%	97.2%	115.3%	129.1%	1,792	High
Waitangirua 11	67%	85.5%	138.7%	147.6%	163.0%	1,825	High
Forecasted Constraints							
Johnsonville 3	67%	<67%	<67%	<67%	72.1%	1,622	Low
Johnsonville 8	67%	<67%	<67%	80.5%	82.5%	474	Low
Kenepuru 9	67%	<67%	76.1%	90.3%	89.5%	546	Medium
Mana 2	67%	<67%	77.2%	78.1%	84.4%	1,600	Medium
Mana 5	67%	<67%	<67%	<67%	69.5%	1,103	Low
Ngauranga 7	67%	<67%	88.2%	89.1%	105.6%	1,264	Medium
Ngauranga 9	67%	<67%	80.7%	95.3%	108.7%	1,046	High
Porirua 2	67%	<67%	77.3%	78.6%	91.1%	1,451	Medium
Porirua 4/5	50%	<67%	78.7%	101.9%	110.6%	446	Medium
Porirua 6	67%	<67%	74.6%	102.1%	103.0%	65	High
Porirua 9	67%	<67%	<67%	<67%	72.6%	1,102	Low
Porirua 12	67%	<67%	90.8%	91.8%	101.9%	1,065	High
Tawa 8	67%	<67%	79.0%	80.3%	91.6%	1,077	Medium
Tawa 13	67%	<67%	74.2%	75.6%	87.3%	984	Medium
Titahi Bay 6	67%	<67%	<67%	<67%	72.6%	844	Low

Table 9-36 Distribution Level Issues

WELL is aware of a number of possible future step load changes identified through customer connection requests, developments detailed in the individual local council District Plans and consultation with city councils, developers, and large customers. A number of property developers and businesses have also flagged developments that may create new loads on the network. The actual outcome and impact of these possible future step change demands is uncertain, and difficult to estimate, and has not been included in the assessment above. WELL will continue to monitor progress with these possible step change demands and develop timely solutions to resolve any network issues arising from the step change demands as they are confirmed.

9.5.4 Summary of Network Development Plan

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

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

9.5.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to evaluate non-network solutions, discussed in Section 9.1.9, to defer investment.

9.5.4.2 Projects for 2024/25

Projects currently underway or planned to start over the next 12 months are listed in Table 9-37.

Project	Description
Waitangirua Link	New 11 kV cable to increase capacity into Whitby.

Table 9-37 Northwestern Area Projects for 2024/25

9.5.4.3 Development Plan Summary

A summary of the development plan for this area is listed in Table 9-38. This information is an extract from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself, for example, many subtransmission constraints can be solved through HV distribution level configuration change or managed operationally by shifting load to adjacent zone substations to relieve overloads.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Project	Description	Constraint Relieved	Target Completion	Investment
Subtransmission				
Waitangirua transformer upgrade	Upgrade transformers to 2 x 36 MVA.	Waitangirua transformers	2030	$15.4 M
Tawa zone substation	Upgrade transformers to 2 x 36 MVA. Upgrade 11 kV switchgear, incomers, and bus coupler to 2500 A.	Tawa transformers	2026	$15.4 M
Tawa 33 kV cables upgrade	Upgrade Tawa 33 kV cables	33 kV cables	2026	$10.0 M
Grenada zone substation	New zone substation at Grenada	Johnsonville, Tawa and Ngauranga zone substations	2028	$35.0 M
Porirua zone substation	Rebuild Porirua zone substation	Porirua zone substation	2026	$29.0 M
Plimmerton zone substation	Rebuild Plimmerton zone substation	Plimmerton zone substation	2027	$45.0 M
Plimmerton traction supply	New 33 kV feeder for Plimmerton traction supply	New traction load	2026	$5.5 M
Plimmerton switching station	New 33 kV switching station	To support zone sub and traction load	2026	$12.4 M
Ngauranga transformer upgrade	Upgrade transformers	Ngauranga transformers	2026	$13.2 M
Distribution				
Waitangirua new feeder	New Waitangirua feeder to supply the Whitby area	Waitangirua 5 and 11	2025	$3.5 M
Whitby cable replacement	Replace section of 11 kV to increase feeder capacity in Whitby area	Waitangirua 5 and 11	2025	$2.0 M
Tawa 8 upgrade	Upgrade Tawa 8 cable section	Tawa 8	2029	$11.2 M
Tawa 13 upgrade	Upgrade Tawa 13 cable section	Tawa 13	2029	$7.0 M
Grenada section upgrade	Replace section of 11kV to increase feeder capacity in Grenada area	Tawa 5 and 11	2029	$2.0 M
Grenada-Ngauranga link	Run overhead line from Grenada to Ngauranga 4	Ngauranga 4, 7 and 9	2029	$0.5 M
New Porirua feeder	New 11 kV feeder	Porirua 4/5 and 6	2029	$11.0 M
New Porirua feeder	New 11 kV feeder	Porirua 12	2029	$11.0 M
Porirua traction supply	New 11 kV feeder for traction supply	New traction load	2026	$5.2 M
New Titahi Bay feeder	New 11 kV feeder	Titahi Bay 6 and 8	2034	$5.0 M
Plimmerton-Mana bus tie upgrade	Upgrade 11 kV tie bus tie between Plimmerton and Mana	Plimmerton-Mana bus tie	2027	$8.7 M
Mana link	New connection between Mana 2 and Waitangirua 3	Mana 2	2028	$2.5 M
Mana 5 upgrade	Mana 5 section upgrade	Mana 5	2032	$3.0 M
Tawa traction supply	New 11 kV feeder for traction supply	New traction load	2026	$2.9 M
New Kenepuru feeder	New 11 kV feeder	Kenepuru 9	2029	$10.9 M
New Johnsonville feeder	New 11 kV feeder	Johnsonville 6	2029	$12.0 M
New Johnsonville feeder	New 11 kV feeder	Johnsonville 11	2028	$10.8 M
Johnsonville 12 upgrade	Johnsonville 12 section upgrade	Johnsonville 12	2030	$4.0 M
Johnsonville 3 upgrade	Johnsonville 3 section upgrade	Johnsonville 3	2032	$2.5 M

Table 9-38 Northwestern Area Development Summary

9.6 Northeastern Area NDRP

This section provides a summary of the Northeastern Area NDRP.

9.6.1 GXP Development Plan

The Northeastern area is supplied from four GXPs. Gracefield and Upper Hutt provide subtransmission supply at 33 kV, while Melling and Haywards GXPs provide supply at 33 kV and 11 kV. Transpower owns all supply transformers and the switchgear at the GXPs. The transformer capacity and the peak system demand are set out in Table 9-39. The forecast in Table 9-39 considers only committed and highly likely developments.

GXP	Continuous Capacity (MVA)	Transformer Cyclic Summer / Winter Capacity (MVA)	Peak Demand (MVA)	
			2023	2033
Gracefield 33 kV	1x60 + 1x85	76 / 80	56	95
Upper Hutt 33 kV	2x40	51 / 53	28	40
Melling 33 kV	2x 50	64 / 65	30	43
Melling 11 kV	2x 25	32 / 34	22	30
Haywards 33 kV	2 x 25[1]	25 / 25	16	32
Haywards 11 kV	2x 30[1]	30 / 30	16	35

Notes:

1. Haywards 33 kV and 11 kV GXPs are supplied from two 110/33/11 kV, 60/25/30 MVA transformers.

Table 9-39 Northeastern Area GXP Capacities

9.6.1.1 Gracefield

The Gracefield GXP comprises two parallel 110/33 kV transformers. one nominally rated at 60 MVA and one rated at 80 MVA, with winter N-1 cyclic capacities of 80 MVA and 113 MVA, respectively. The maximum demand on the Gracefield GXP was 56.5 MVA in 2023. The Gracefield peak demand is forecast to exceed the 33 kV N-1 capacity in 2029, due to demand growth as a result of electrification.

9.6.1.2 Haywards

There are two parallel 110/33/11 kV, three-winding, 60/25/30 MVA transformers at Haywards that provide N-1 supply to:

- Trentham zone substation via two 33 kV circuits, and
- Haywards 11 kV switchboard.

The maximum demand in 2023 was 16.4 MVA on the Haywards 33 kV GXP, and 16.0 MVA on the Haywards 11 kV GXP.

The Haywards peak demand is forecast to exceed the 33 kV N-1 capacity in 2027, due to demand growth in the Trentham area. WELL plans to construct a new switching station in 2028 that will transfer much of this additional demand to Upper Hutt GXP.

9.6.1.3 Upper Hutt

The Upper Hutt GXP comprises two parallel 110/33 kV transformers each nominally rated at 40 MVA with a winter N-1 cyclic capacity of 53 MVA. The maximum demand on the Upper Hutt GXP in 2023 was 28.2 MVA. Upper Hutt supplies zone substations at Brown Owl and Maidstone each via double 33 kV circuits.

9.6.1.4 Melling

Melling has a 33 kV GXP and an 11 kV GXP.

The Melling 33 kV GXP comprises two parallel 110/33 kV transformers each nominally rated at 50 MVA with a winter N-1 cyclic capacity of 65 MVA. The maximum demand on the Melling 33 kV GXP in 2023 was 30.0 MVA. Melling 33kV GXP supplies zone substations at Naenae and Waterloo, each via double 33 kV circuits.

The Melling 11 kV GXP comprises two parallel 110/11 kV transformers each nominally rated at 25 MVA with a winter N-1 cyclic capacity of 34 MVA. The maximum demand on the Melling 11 kV GXP in 2023 was 22.3 MVA. The Melling 11 kV GXP supplies the WELL network directly from a Transpower-owned 11 kV switchboard.

9.6.2 Subtransmission Network Development Needs

This section describes the identified security of supply constraints and development needs for the Northeastern Area.

The Northeastern network consists of 18 subtransmission 33 kV circuits supplying nine zone substations. Each zone substation supplies the 11 kV distribution network with interconnectivity via switched open points to adjacent zones. The Haywards and Melling 11 kV switchboards directly feed into the distribution network. The characteristics of each zone substation are listed in Table 9-40.

Zone Substation	Season	Subtransmission N-1 branch rating (MVA)		Constraining Branch Component[42]	Peak Demand C1 (MVA)		Year Constraint Binding			ICP Counts as at 2023
		Existing	Post - upgrade		2023	2033	C1	C2	C3	
Existing Constraints										
Korokoro	Winter	15.5	N/A	33kV Cable	18.8	27.1	Existing			3,863
	Summer	13.3	N/A	33kV Cable	14.0	21.4	Existing			
Seaview	Winter	13.8	N/A	33kV Cable	15.1	22.8	Existing			3,661
	Summer	10.6	N/A	33kV Cable	12.1	19.6	Existing			
Waterloo	Winter	20.1	N/A	33kV Cable	16.7	26.5	2025	2025	2025	6,040
	Summer	12.0	N/A	33kV Cable	12.6	22.3	Existing			
Forecasted Constraints										
Brown Owl	Winter	18.4	22.0	Transformer	16.0	20.4	2026	2026	2026	6,857
	Summer	12.9	22.0	33kV Cable	10.6	15.4	2026	2026	2025	
Gracefield	Winter	23.0	N/A	Transformer	10.7	29.0	2030	2028	2027	2,753
	Summer	23.0	N/A	Transformer	9.8	26.3	2031	2029	2027	
Maidstone	Winter	17.6	20.0	33kV Cable	14.7	22.7	2025	2025	2025	4,396
	Summer	10.2	20.0	33kV Cable	10.2	18.0	2024	2024	2024	
Naenae	Winter	18.3	N/A	33kV Cable	15.0	19.8	2029	2029	2026	6,461
	Summer	13.9	N/A	33kV Cable	9.4	14.1	2033	2031	2027	
Trentham	Winter	19.1	N/A	33kV Cable	16.6	33.0	2024	2024	2024	6,087
	Summer	14.7	N/A	33kV Cable	10.6	26.5	2025	2025	2025	
Wainuiomata	Winter	20.0	N/A	Transformer	17.7	25.5	2026	2026	2025	7,275
	Summer	20.0	N/A	Transformer	10.9	18.1	2037	2036	2034	

Table 9-40 Northeastern Area Zone Substation Capacities

9.6.2.1 Brown Owl

The peak demand supplied by Brown Owl is currently within the N-1 capacity of the zone substation. Table 9-41 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Subtransmission N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Brown Owl	Winter	18.4	16.0	0
	Summer	12.9	10.6	0

Table 9-41 Current Brown Owl Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Brown Owl is forecast to grow as show in Figure 9-27.

[42] Subtransmission branch consists of incoming 33kV circuits, the 33/11kV transformer and the 11 kV incomer circuit breakers

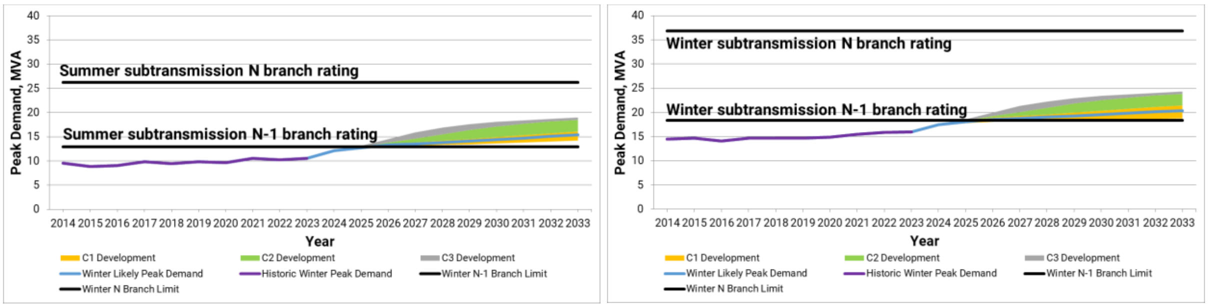


Figure 9-27 Brown Owl Demand Forecast

The Brown Owl peak demand is forecast to exceed the subtransmission N-1 capacity in 2026. WELL will continue monitoring load growth and manage any developing overloading risk through operational controls.

9.6.2.2 Gracefield

The peak demand supplied by Gracefield is currently within the N-1 capacity of the subtransmission circuits. Table 9-42 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Gracefield	Winter	23.0	10.7	0
	Summer	23.0	9.8	0

Table 9-42 Current Gracefield Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Gracefield is forecast to grow as shown in Figure 9-28. The subtransmission capacity constraints are plotted for comparison.

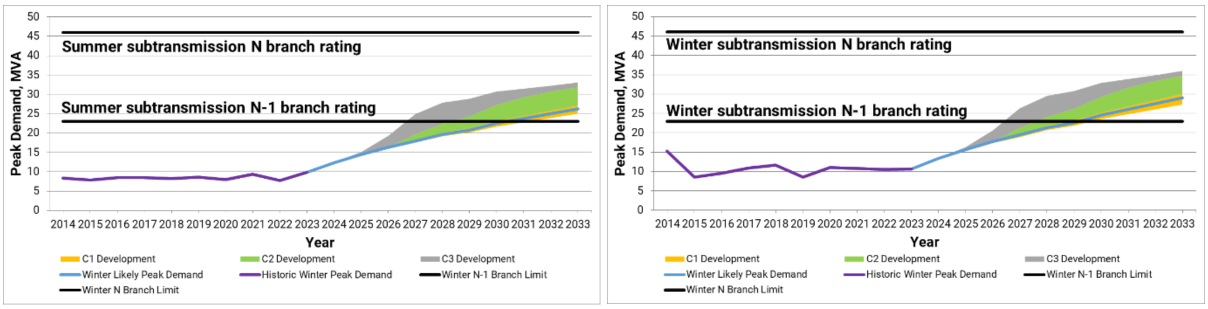


Figure 9-28 Gracefield Demand Forecast

The Gracefield peak demand is forecast to exceed the subtransmission N-1 capacity in 2030. WELL will continue monitoring load growth and manage any developing overloading risk through operational controls.

9.6.2.3 Haywards

The peak demand supplied by Haywards is currently within the N-1 capacity of subtransmission circuits. Table 9-43 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Haywards	Winter	30.0	16.4	0
	Summer	30.0	11.0	0

Table 9-43 Current Haywards Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Haywards is forecast to grow as shown in Figure 9-29. The subtransmission capacity constraints are plotted for comparison.

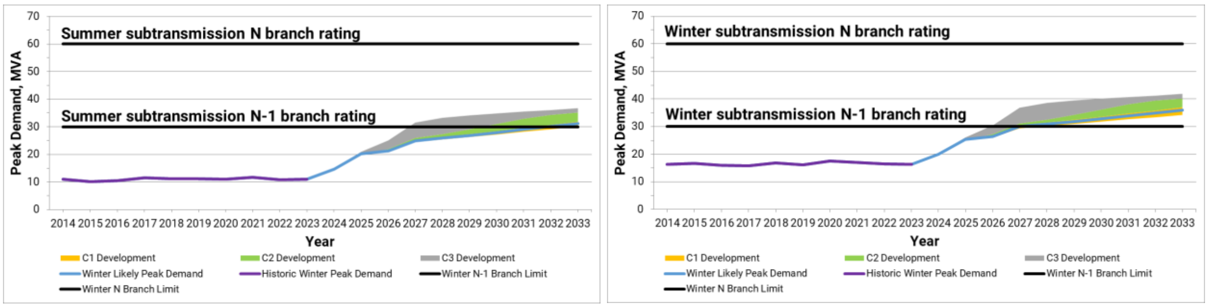


Figure 9-29 Haywards Demand Forecast

The Haywards peak demand is forecast to exceed the subtransmission N-1 capacity in 2027, due to demand growth in the Trentham area. WELL will continue monitoring load growth and manage any developing overloading risk through operational controls.

9.6.2.4 Korokoro

The peak demand at Korokoro currently exceeds the N-1 capacity of subtransmission circuits. Table 9-44 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Korokoro	Winter	15.5	18.8	3.3
	Summer	13.3	14.0	0.7

Table 9-44 Current Korokoro Subtransmission Constraints

Based on the estimated growth scenarios and development within the planning period, the peak demand at Korokoro is forecast as shown in Figure 9-30. The subtransmission capacity constraints are plotted for comparison.

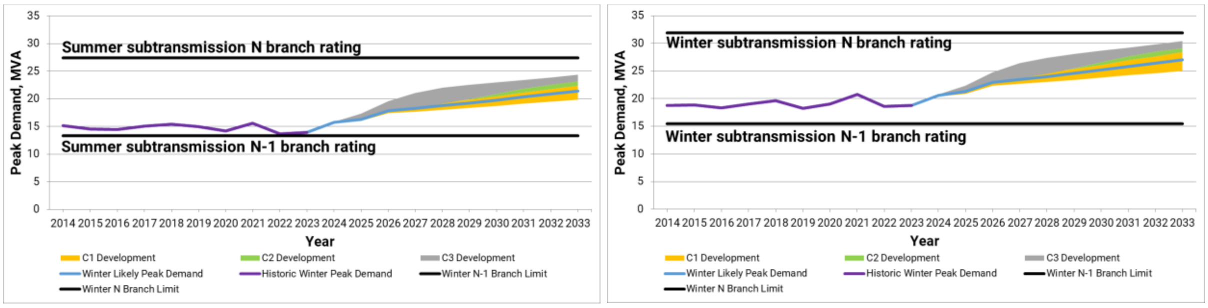


Figure 9-30 Korokoro Load Forecast

The Korokoro 33 kV subtransmission capacity is currently limited by a constraint on the 33 kV subtransmission cables. WELL plans to redevelop Petone zone substation in 2027 in order to transfer load away from Korokoro, and until then will continue monitoring load growth and manage the overloading risk through operational control by shifting load to adjacent zone substations to relieve overloads.

Alternative options for managing the constraint at Korokoro are:

1. Relocating 11 kV cables away from the Korokoro subtransmission cables outside Seaview zone substation, to remove a thermal pinch point. This is a cost-effective option that WELL is investigating, however, it is only a short-term solution and on its own is insufficient to meet the longer-term load growth.

2. To replace and upgrade the 33/11 kV transformers and the 33 kV cables. This option is less favoured, as redeveloping Petone increases security of supply in the area due to taking supply from a different GXP.

9.6.2.5 Maidstone

The peak demand supplied by Maidstone currently exceeds the N-1 capacity of subtransmission circuits in summer. Table 9-45 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Maidstone	Winter	17.6	14.7	0
	Summer	10.2	10.2	0

Table 9-45 Current Maidstone Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Maidstone is forecast to grow as show in Figure 9-31.

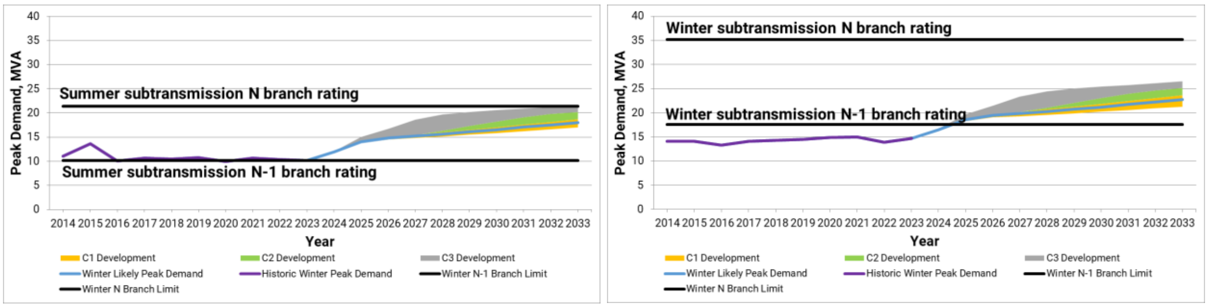


Figure 9-31 Maidstone Demand Forecast

The Maidstone peak demand currently exceeds the summer subtransmission N-1 capacity and is forecast to exceed the winter subtransmission N-1 capacity by 2025. The constraining 33 kV subtransmission cables are planned for replacement due to asset health in 2032 as identified in Section 8.5.1. In the interim, security of supply will be managed operationally by shifting load to adjacent zone substations to relieve overloads. An 11 kV switching station project, proposed for 2028, will enhance the ability to do this.

9.6.2.6 Melling

The peak demand supplied by Melling is currently within the N-1 capacity of subtransmission circuits. Table 9-46 shows the seasonal constraint levels and the minimum offload requirements on each circuit.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Melling	Winter	34.0	23.1	0
	Summer	32.0	16.3	0

Table 9-46 Current Melling Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Melling is forecast to grow as show in Figure 9-32.

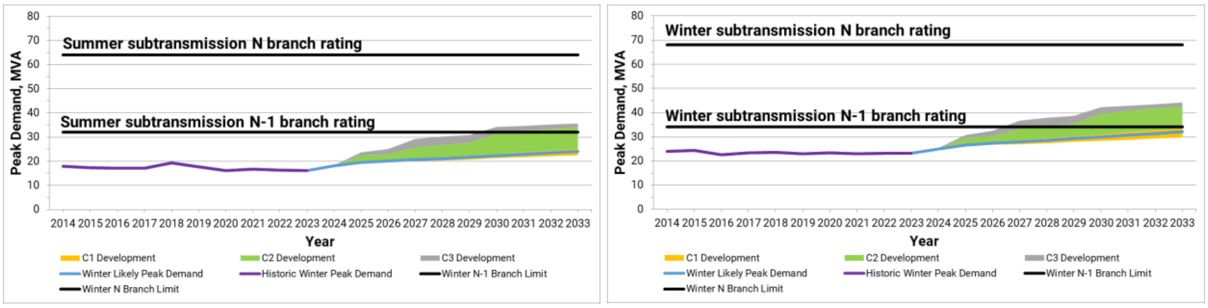


Figure 9-32 Melling Demand Forecast

9.6.2.7 Naenae

The peak demand supplied by Naenae is currently within the N-1 capacity of the subtransmission circuits. Table 9-47 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Naenae	Winter	18.3	15.0	0
	Summer	13.9	9.4	0

Table 9-47 Current Naenae Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Naenae is forecast to grow as show in Figure 9-33. Without action, the winter peak load is forecast to exceed the N-1 subtransmission capacity from 2028.

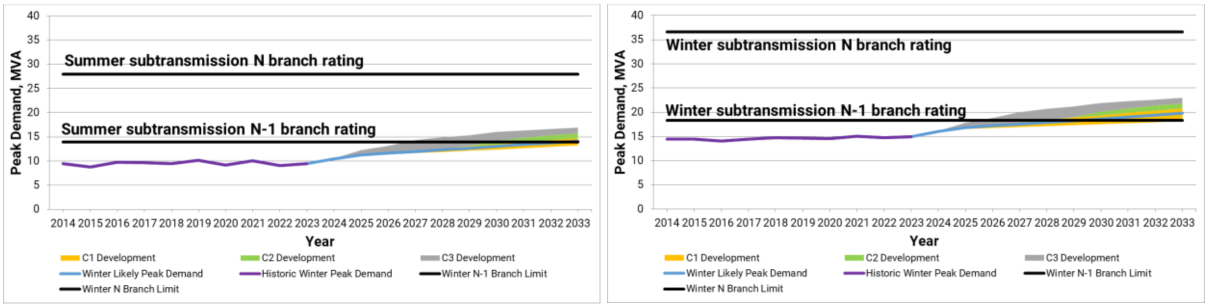


Figure 9-33 Naenae Demand Forecast

WELL will monitor load growth and manage the overloading risk by shifting open points on the 11 kV feeders and through operational control by shifting load to adjacent zone substations to relieve overloads.

9.6.2.8 Seaview

The peak demand supplied by Seaview currently exceeds the summer and winter N-1 capacity of the subtransmission circuits. Table 9-48 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Seaview	Winter	13.8	15.1	1.3
	Summer	10.6	12.1	1.5

Table 9-48 Current Seaview Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Seaview is forecast to grow as show in Figure 9-34.

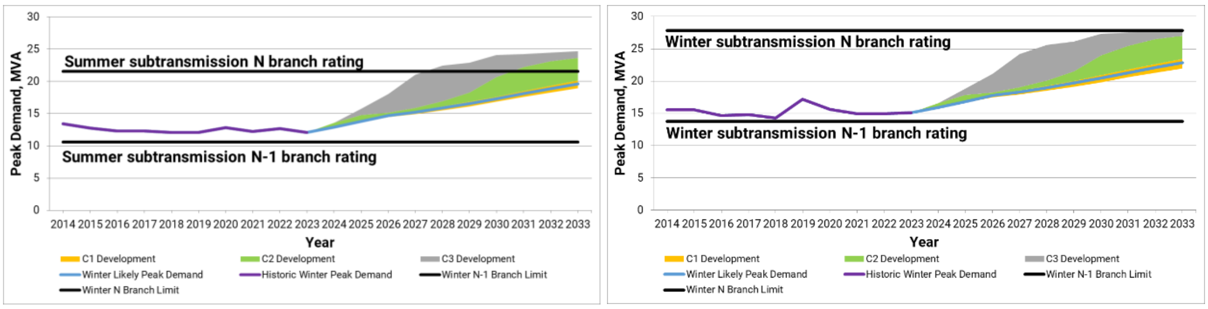


Figure 9-34 Seaview Demand Forecast

WELL plans to reactivate Petone zone substation in 2027, which will transfer load away from Seaview, and until then will continue monitoring load growth and manage the overloading risk through operational control by shifting load to adjacent zone substations to relieve overloads.

Alternative options for managing the constraint at Seaview are:

1. Relocating 11 kV cables outside Seaview zone substation, to remove a thermal pinch point on the subtransmission cables. This is a cost-effective option that WELL is investigating, however, it is only a short-term solution and on its own is insufficient to meet the longer-term load growth.

2. To replace and upgrade the 33/11 kV transformers and the 33 kV cables. This option is less favoured, as reactivating Petone increases the security of supply in the area due to taking supply from a different GXP.

9.6.2.9 Trentham

The peak demand supplied by Trentham is currently within the N-1 capacity of the subtransmission circuits. Table 9-49 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Trentham	Winter	19.1	16.6	0
	Summer	14.7	10.6	0

Table 9-49 Current Trentham Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Trentham is forecast to grow as show in Figure 9-35. The forecast load growth could come from proposed residential subdivisions and commercial developments in the area.

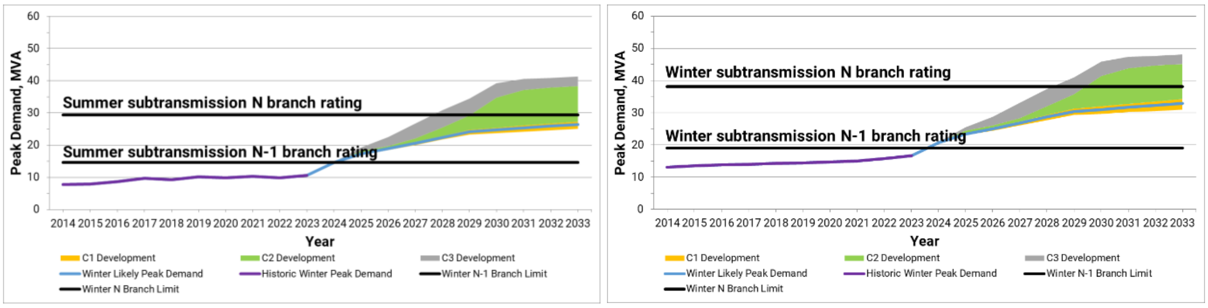


Figure 9-35 Trentham Demand Forecast

The Trentham winter peak demand is likely to exceed the subtransmission N-1 capacity from 2024, and the N-1 capacity of the Haywards 33 kV supply transformers in 2027.

With the ultimate capacity at Trentham being limited by the 25 MVA transformers at Haywards GXP, WELL is proposing to build a switching station in the area, to facilitate the transfer of load between Trentham and Maidstone zone substation via the 11 kV network.

9.6.2.10 Wainuiomata

The peak demand supplied by Wainuiomata currently within the N-1 capacity of the subtransmission circuits. Table 9-49 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Wainuiomata	Winter	20.0	17.7	0
	Summer	20.0	10.9	0

Table 9-50 Current Wainuiomata Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loads within the planning period, the demand at Wainuiomata is forecast to grow as shown in Figure 9-36. The forecast load growth will come from proposed residential subdivisions and commercial developments in the area.

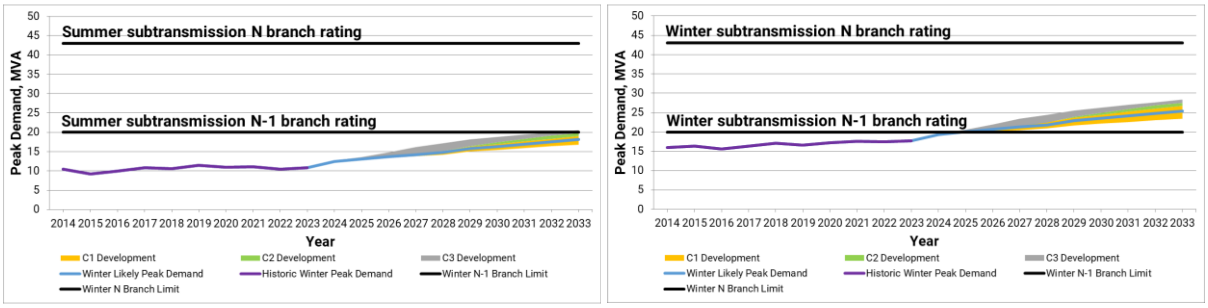


Figure 9-36 Wainuiomata Demand Forecast

WELL will continue to monitor the load growth and will investigate options to mitigate the system constraints as possible step load growth gets confirmed.

9.6.2.11 Waterloo

The peak demand supplied by Waterloo is currently exceeding the summer N-1 capacity of the subtransmission circuits. Table 9-50 shows the seasonal constraint levels and the minimum offload requirements.

Zone substation	Season	Constraining N-1 branch rating (MVA)	Peak Demand @2023 (MVA)	Minimum offload for N-1 @ peak (MVA)
Waterloo	Winter	20.1	16.7	0
	Summer	12.0	12.6	0.6

Table 9-51 Current Waterloo Subtransmission Constraints

Based on the estimated growth scenarios and confirmed step change loaded within the planning period, the load at Waterloo is forecast to grow as shown in Figure 9-37.

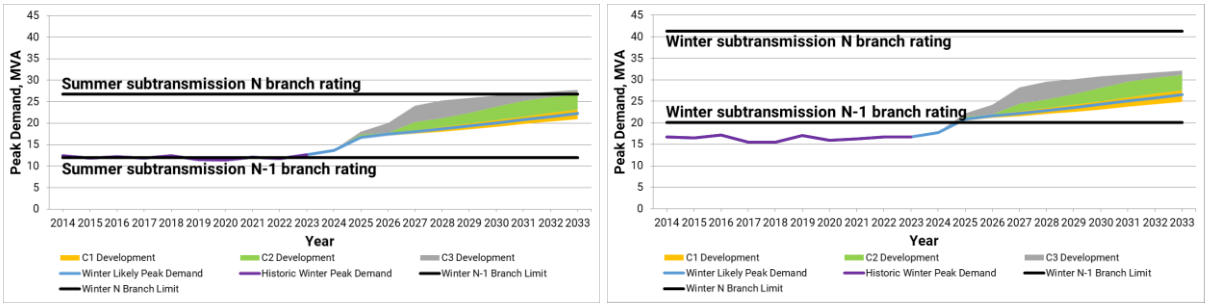


Figure 9-37 Waterloo Demand Forecast

WELL will investigate options to mitigate system constraints as possible step load growth gets confirmed. The constraining 33 kV subtransmission cables are planned for replacement due to asset health in 2033 as identified in Section 8.5.1.

9.6.3 Distribution Level Development Needs

Table 9-52 shows where the applicable security criteria for the 11 kV feeder configurations are exceeded under the C1 and C2 load forecasts, based on forecast demand growth and confirmed step load changes. This is used to determine whether further contingency analysis of each individual feeder is required. Alongside each feeder is the priority level of the planning and investment requirements.

There are no meshed feeders in the Northeastern Area, so all feeders are radial with a 67% security criteria as defined in Table 9-3.

Feeder	Loading Criteria	Present Loading	+5 years Loading C1	+5 years Loading C2	+5 years Loading C3	Feeder ICP Count	Priority
Existing Constraints							
Brown Owl 8	67%	70.1%	78.2%	88.4%	95.6%	1,407	Medium
Gracefield 7	67%	76.2%	175.4%	210%	211.2%	27	High
Haywards 2722	67%	75.7%	95.4%	96.6%	116.1%	1,522	High
Haywards 2822	67%	92.8%	151.8%	153.6%	183.5%	1,393	High
Waterloo 5	67%	73.6%	97.4%	98.6%	121.6%	1,721	High
Forecast Constraints							
Brown Owl 2	67%	<67%	72.5%	80.7%	85.8%	1,180	Low
Brown Owl 5	67%	<67%	<67%	76.8%	78.9%	1,058	Low
Gracefield 3	67%	<67%	101.2%	102.6%	140.7%	1,050	Medium
Gracefield 9	67%	<67%	110.7%	112.4%	157.6%	1,059	High
Gracefield 12	67%	<67%	93.2%	113.6%	128.8%	402	Medium
Haywards 2702	67%	<67%	71.4%	72.5%	91.0%	1,304	Low
Haywards 2742	67%	<67%	98.5%	98.5%	99.5%	68	Low
Haywards 2782	67%	<67%	74.4%	75.1%	87.4%	964	Low
Haywards 2842	67%	<67%	129.2%	168.6%	175.6%	365	High
Maidstone 6	67%	<67%	73.7%	74.4%	83.0%	1,054	Low
Naenae 6	67%	<67%	70.1%	71.0%	77.5%	1,407	Low
Seaview 6	67%	<67%	<67%	67.1%	70.1%	172	Low
Seaview 12	67%	<67%	85.8%	85.9%	119.2%	1,493	Medium
Trentham 3	67%	<67%	72.8%	73.1%	79.8%	869	Low
Trentham 5	67%	<67%	82.9%	125.4%	134.0%	888	Low
Trentham 6	67%	<67%	67.7%	90.0%	122.2%	23	High
Trentham 12	67%	<67%	71.0%	71.6%	85.3%	1,241	Low
Waterloo 3	67%	<67%	<67%	76.7%	81.8%	480	Low
Waterloo 6	67%	<67%	71.4%	71.9%	81.5%	951	Low
Waterloo 9	67%	<67%	110.7%	126.8%	130.2%	310	High
Wainuiomata 6	67%	<67%	78.3%	79.3%	85.5%	1,534	Low

Table 9-52 Distribution Level Issues

WELL is aware of a number of possible future step load changes identified through customer connection requests, developments detailed in the local council District Plans and consultation with City Councils, developers, and large customers. A number of property developers and businesses have also flagged developments that may create new loads on the network.

The actual outcomes and impacts of these possible future step load change demands are uncertain, difficult to estimate, and have not been included in the assessment above. WELL will continue to monitor progress with these possible step change demands and develop timely solutions to resolve any network issues arising from the step change demands as they are confirmed.

9.6.4 Summary of Network Development Plan

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

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

9.6.4.1 Non-network Solutions

Prior to any investment in any infrastructure being considered, the first step is to evaluate non-network solutions, discussed in Section 9.1.9, to defer investment.

9.6.4.2 Development Plan Summary

A summary of the development plan for this area is listed in Table 9-53. This information is an extraction from the NDRP, which provides detailed development options and feasibility analysis.

Each constraint is identified as an individual issue, but the overall development plan for the region is optimised through a shortlisting process. The most feasible solution may not be the replacement of the constrained asset itself. For example, many subtransmission constraints can be solved through 11 kV distribution level configuration changes and/or be managed operationally by temporarily shifting load to adjacent zone substations to relieve overloads.

Detailed project planning and option engineering will be completed at the project scope development and approval stage.

Project	Description	Constraint Relieved	Target Completion	Investment
Subtransmission Constraints				
New Switching Station between Trentham and Maidstone	Build a new switching station with zone substation potential between Trentham and Maidstone.	Trentham 33kV cables, Maidstone 33kV cables, Haywards transformers, Trentham 3, 5, and 6	2028	$19 M
Additional cables into switching station between Trentham and Maidstone	Install 33 kV rated cables between Trentham 5/12 and the new switching station.	Maidstone 33kV cables, Trentham 3, 5, and 6	2029	$15 M
Petone Zone Substation	Redevelop Petone zone substation	Korokoro 33kV cables	2027	$45 M
Brown Owl Transformers	Replace 33/11 kV transformers at Brown Owl Substation	Brown Owl Transformers	2030	$11.1 M
Wainuiomata Transformers	Replace 33/11 kV transformers at Wainuiomata Substation	Wainuiomata Transformers	2030	$13.3 M
Distribution Constraints				
Brown Owl 11kV	New feeder to Totara Park	Brown Owl 2	2028	$5.0 M
	New feeder to Moeraki Rd	Brown Owl 8	2028	$4.6 M
	New feeder to Maymorn	Brown Owl 5	2027	$2.7 M
Trentham 11kV	Upgrade feeder front end	Trentham 12	2029	$9.2 M
	New feeder to Blue Mountains Rd	Haywards 2722	2028	$11.7 M
	New feeder	New traction load	2026	$0.8 M
Haywards 11kV	Upgrade to Benmore Crescent	New traction load	2027	$7.0 M
	Upgrade the feeder front end	Haywards 2822	2024	$3.2 M
Maidstone 11kV	Upgraded feeder	New traction load	2027	$1.3 M
Naenae 11kV	New feeder to Western Hutt Rd	Haywards 2842	2028	$14.1 M
	Upgrade the feeder front end	Naenae 6	2029	$1.5 M
Korokoro 11kV	New feeder	New traction load	2027	$2.8 M
Gracefield 11kV	New feeder to Totara St New tie between Gracefield 3 and Gracefield 9	Gracefield 3, Gracefield 9	2026	$13.0 M
	New feeder to Gracefield Rd	Gracefield 4	2030	$3.5 M
	New feeder to Cambridge Terrace	Gracefield 7, Waterloo 9	2027	$4.1M
Petone 11	Upgrade feeder front end	Petone 7	2030	$3.1 M
Wainuiomata 11kV	Upgraded section of 11 kV cable	Wainuiomata 6	2029	$5.0 M
	Install Voltage Regulator	Wainuiomata 7	2027	$0.5 M
Waterloo 11kV	Upgraded section to Witako Street	Waterloo 6	2029	$4.4 M
	New feeder	Waterloo 5, Seaview 12	2028	$7.2 M

Table 9-53 Northeastern Area Development Summary

9.7 Low Voltage Reinforcement

Historically, LV capacity has been invisible to distribution network planners, preventing the development of LV network growth CAPEX. Networks have not been funded to develop the tools and processes to provide visibility of the LV network, manage the connection of large new customer devices, and incorporate flexibility.

Given the expected rapid demand growth in Wellington outlined in Section 4, WELL commissioned ANSA to provide a LV constraint risk tool which:

1. Establishes the hosting capacity of each LV asset on each residential LV network.
2. Applies a demand forecast to those assets.
3. Identifies when those assets will run out of capacity.
4. Applies a standard cost model to each asset that needs reinforcing with additional capacity.
5. Aggregates those costs to provide a CAPEX forecast for the next 50 years.

The study expands the 10-network study provided in Section 4.2.1.3 of WELL's 2023 AMP, which modelled the impact of the residential gas transition on small sample of LV networks. The new study includes all residential LV networks in Wellington, and models new demand from EV uptake as well as the gas transition.

Since this work is not funded by DPP allowances, WELL has submitted an Innovation Project Allowance application, and has had to find savings from other parts of the business to fund the 50% share that is not covered by the innovation mechanism. Accessing data has been difficult, relying on one-off data requests from Retailers to avoid high data purchase costs.

In future, networks will need funding to develop tools and processes that provide on-going visibility of the LV network. WELL intends to incorporate the ANSA solution into business-as-usual processes, with the next steps including increasing the spatial resolution of the underlying growth forecasts. It is also necessary to develop other capabilities not provided by the ANSA tool, including near-real-time constraint and capacity monitoring, and tools to incorporate and manage flexibility.

9.7.1 Methodology

The ANSA tool builds a spatial model of LV assets, including customer ICPs, the transformers that supply those connections, and the connecting conductors. The model allows different power flows to be applied to the network models, testing whether each asset has the capacity to host changes in electricity demand.

The ANSA model then applies different growth models to the network models. The model uses Monte Carlo simulation to calculate the impact on the capacity of the LV assets for different combinations of:

- EV uptake rates;
- Gas to electricity transition;
- EV charger size (1.8 kW, 3.7 kW, 7.4kW), and
- EV charging times (6pm, 9pm, 12am, 3am)

The simulation provides a probability of when each asset will exceed its capacity, then applies standardised costs for the reinforcement of each constrained asset. The aggregated reinforcement costs form the network growth CAPEX.

9.7.2 Study Scope

The Wellington network is a winter evening peaking network and residential customers drive peak demand. The study therefore focused on residential LV networks. The study assessed 1,777 residential urban LV networks, capturing the majority of residential customers.

Rural networks below 100kVA were excluded as they supply fewer customers, resulting in higher design ADMDs, and are also less likely to have reticulated gas connections.

Commercial and industrial networks were also excluded as they are unlikely to be contributing to winter evening peak demand, and increases in demand are more likely to require customer-initiated projects, allowing constraints to be identified and resolved before they occur.

9.7.3 Assumptions and Limitations

The following assumptions and limitations apply:

1. There may be factors other than capacity constraints that trigger conductor and transformer replacement, such as age and condition. Only reinforcement due to load increases is considered in this study.

2. It is assumed that there are no mechanical constraints in upgrading conductors. These upgrades may be limited by wind and other structural loading.

3. The determination of customers with gas connections, assessment of gas consumers' demand, and the assignment of demand during modelling is limited due to imperfections in ascertaining gas consumers, and the nature of their gas use (i.e. cooking, water heating, and space heating).

4. The CAPEX forecast used for this AMP is the expenditure required to address constraints that the model assesses as being certain to occur. As such, the forecast is conservative, reflecting only highly certain expenditure, and there may be other lower probability constraints that occur that have not been accounted for in the forecast. WELL and ANSA are exploring options for further developing the forecasting methodology.

9.7.4 Results

The study tested a range of different charging behaviour and the following growth scenarios:

- Slow Decarbonisation: slow uptake of electric vehicles, and no gas transition.
- Expected Scenario: moderate uptake of electric vehicles, and slow gas transition.
- Rapid Decarbonisation: rapid uptake of electric vehicles, and rapid gas transition.

Table 9-54 provides the number of LV networks constrained for each growth scenario. The study found that about 12% of LV networks already have no spare capacity during winter peaks. A further 1.3% to 14% of networks would become constrained by 2030 depending on the actual demand growth rate. By 2050, the majority of networks (61% to 64%) will have become constrained.

Decarbonisation Scenarios	2023	2025	2030	2035	2040	2045	2050	Total
Slow Decarbonisation Scenario	217	0	24	0	232	189	420	**1,082**
Expected Decarbonisation Scenario	217	24	0	221	183	203	226	**1,074**
Rapid Decarbonisation Scenario	217	24	221	183	192	301	0	**1,138**

Table 9-54 Forecast of number of LV Network Becoming Constrained by Period and Growth Scenario

Figure 9-38 provides the cumulative CAPEX for these three growth scenarios. The majority of the constraints that need to be solved by 2030 already exist for both the slow and moderate scenarios. The cumulative capex required by 2030 would double if EV uptake and the gas transition were rapid.

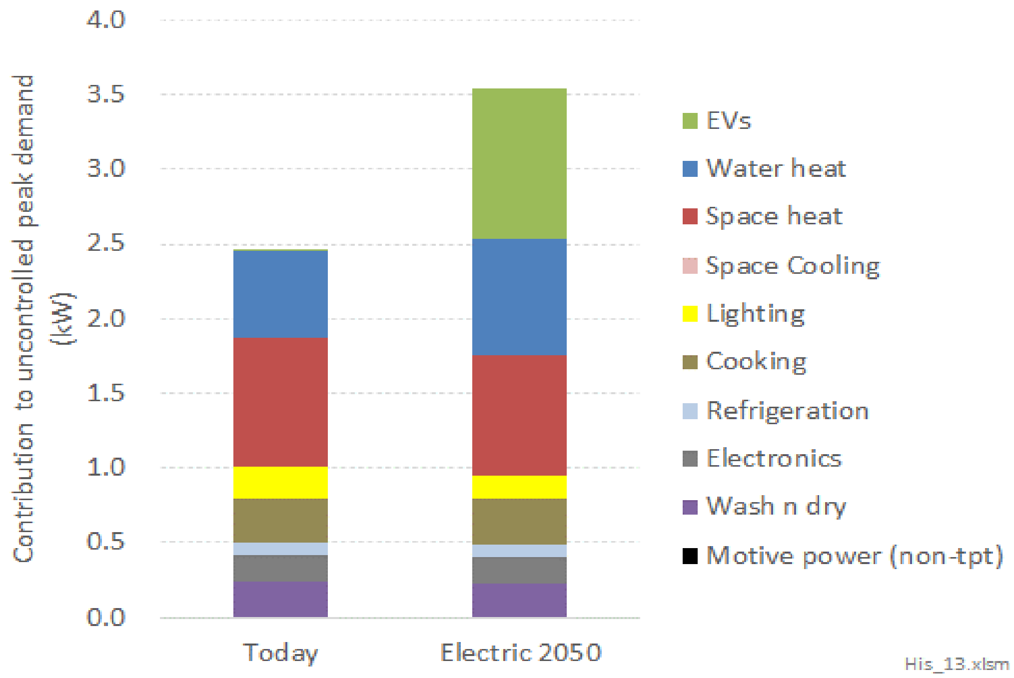


Figure 9-38 Cumulative LV Reinforcement CAPEX by Regulatory Period and Growth Scenario

The study also tested the impact of changing EV charging behaviour. Figure 9-39 compares the total network growth capex for the 50-year study period for three charger types and four charging times. It found that CAPEX is very sensitive to charger size and charge time, highlighting the importance of ensuring that large EV chargers are participating in flexibility services. Customers could avoid $234m in CAPEX if charger size is restricted to an average of 3.7kW and charging only starts after midnight.

Note that while CAPEX can be avoided if demand can be shifted to off-peak periods, networks will still incur OPEX costs to purchase the demand shift as a flexibility service, and would have to invest in the tools and processes to incorporate flexibility services into their asset management processes. The actual savings would depend on how much of the value of deferring CAPEX investment is passed through to customers as flexibility payments.

safer together

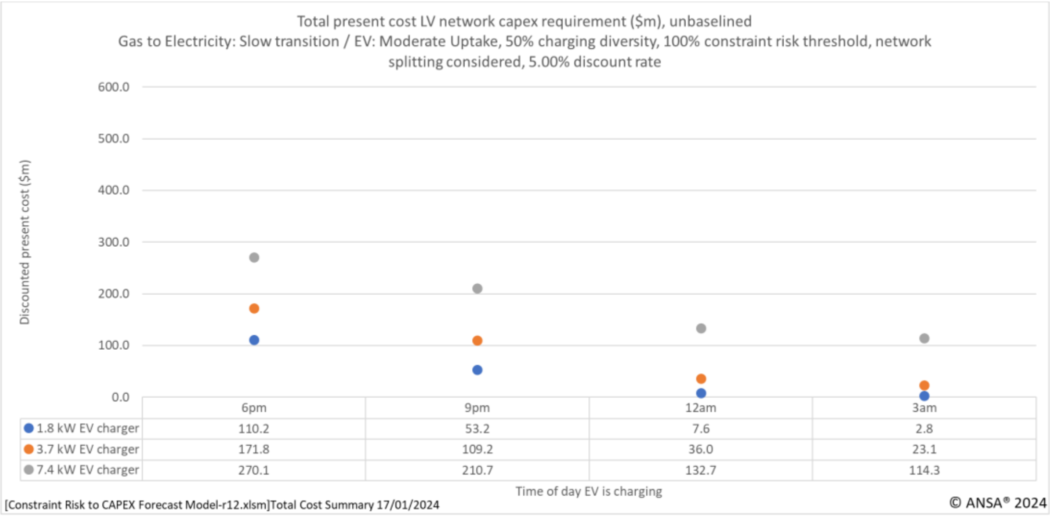


Figure 9-39 Impact of Charging Behaviour on LV Reinforcement CAPEX

9.7.4.1 AMP Scenario

We have selected a base scenario which aligns with current EV consumption patterns and a growth profile which aligns with our current AMP assumptions. Specially:

- An average EV charger size of 3.7 kW reflecting the average EV charger currently being offered.
- A 6pm charging time and 50% EV charging diversity reflecting current charging habits. This provides benchmark for assessing the benefits of investing in flexibility services. If it is more efficient to do so, then a network would substitute CAPEX for the OPEX needed to purchase flexibility.
- Slow gas transition growth and moderate EV growth rates. The growth rates align with New Zealand Emissions Reduction Plan and WELL's wider AMP growth assumptions, and are summarised in Table 9-55.

Asset Type	2023	2025	2030	2035	2040	2045	2050
Residential Gas Penetration	33%	31%	28%	25%	21%	18%	15%
Electric Vehicle Uptake	4%	11%	28%	46%	64%	81%	99%

Table 9-55 Growth Rates Used in Expected Decarbonisation Scenario

Table 9-56 provides a breakdown of the number of assets that are constrained in each regulatory period. Transformers are the most constrained assets. Approximately 10% of the studied LV networks are currently constrained and a future 2% will be constrained in the DPP4 regulatory period.

Asset Type	2023	2025	2030	2035	2040	2045	2050
Transformer Upgrades	192	217	217	433	611	807	1,028
Additional Transformers	16	16	16	24	32	37	39
LV Underground Cables (km)	11.07	12.38	12.38	17.92	27.10	39.92	63.15
LV Overhead Lines (km)	6.7	6.7	6.7	10.6	16.2	28.1	46.8

Table 9-56 Number of LV Assets Needing Upgrading

Figures 9-40 to 9-42 geographically illustrate the LV assets which will become constrained in the period up to 2030, the end of the DPP4 regulatory period. The LV assets in these areas tend to be old networks which were built using old network design standards. The highlighted areas are also suburbs where there have been large amounts of high-density infill housing.

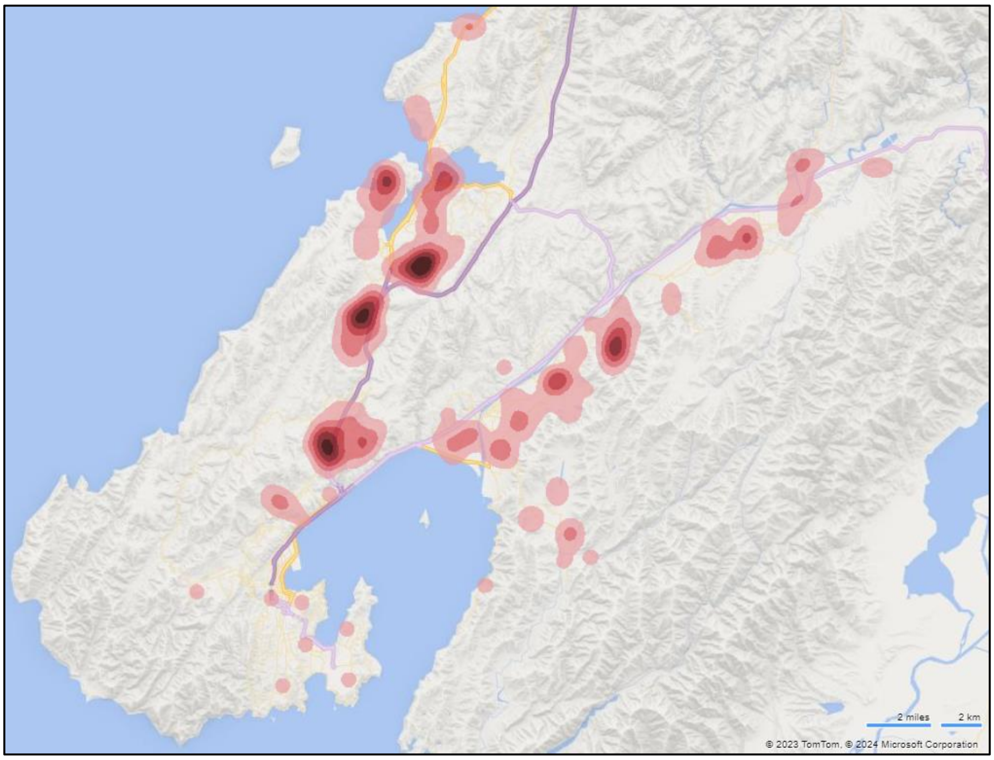


Figure 9-40 Distribution Transformer Constraints to 2030

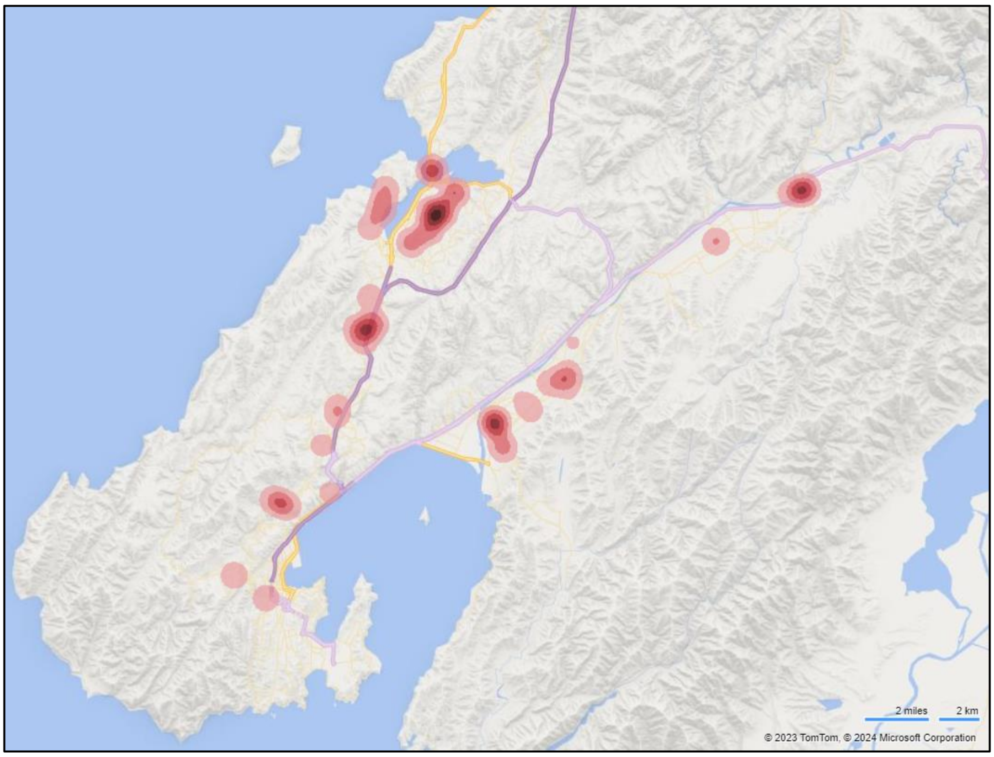


Figure 9-41 LV Underground Cable Constraints to 2030

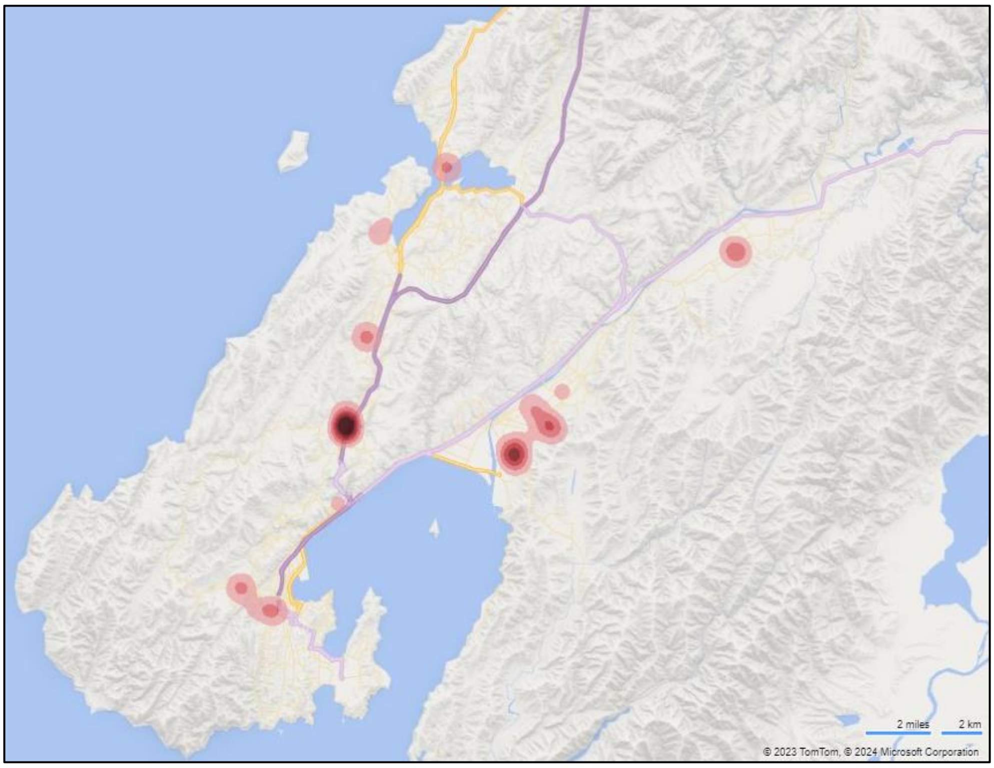


Figure 9-42 LV Overhead Line Constraints to 2030

Figure 9-43 summarises the ratings of the transformers which are becoming constrained, as a percentage of the total number of transformers of that rating. The graph shows that the transformer sizes most likely to become constrained are smaller pole-mounted or ground-mounted transformers. This is consistent with the view that the most constrained networks are networks built using design old design standards that assumed smaller household loads, in older suburbs with a higher proportion of subdividable properties.

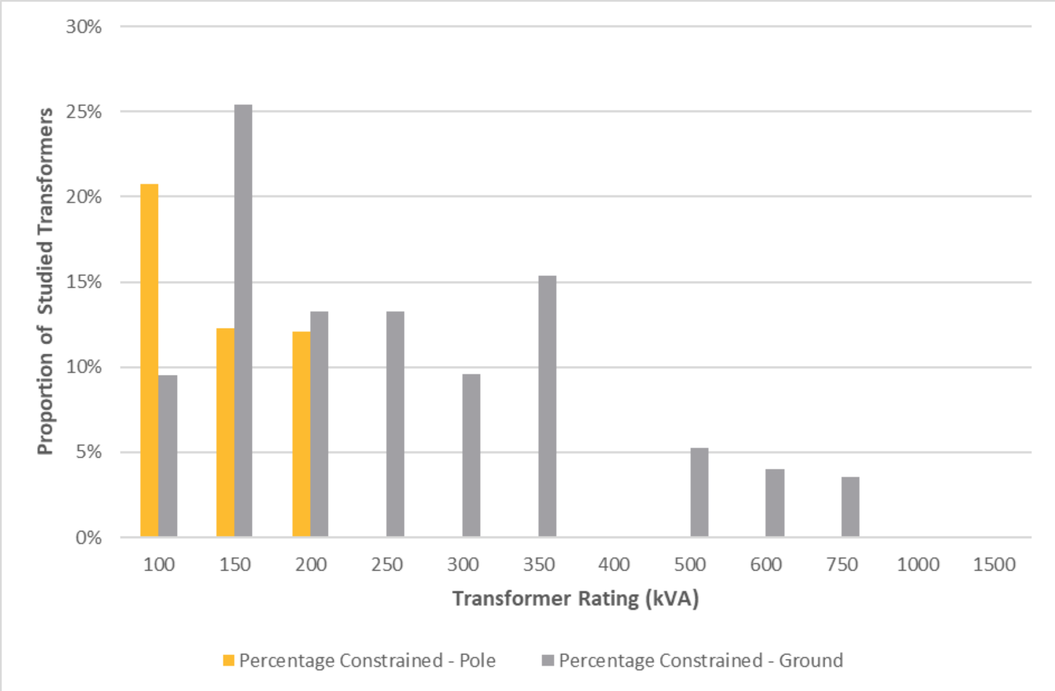
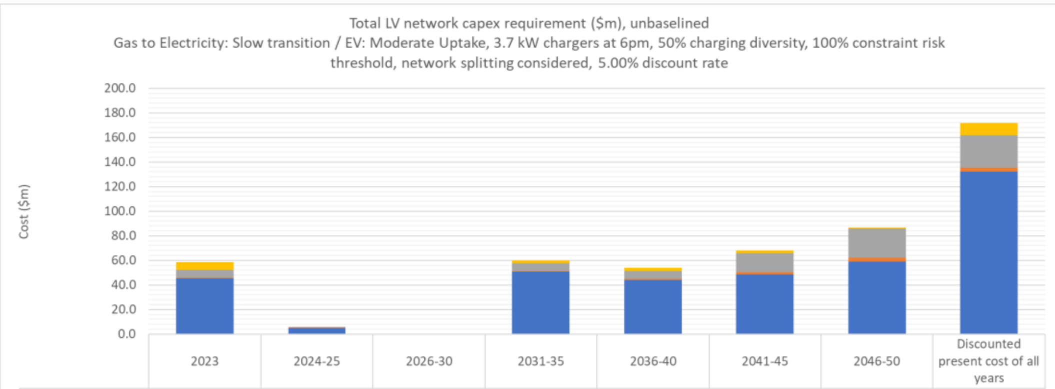


Figure 9-43 Constrained Transformers by Rating as Proportion of Fleet

Figure 9-44 provides a forecast of the CAPEX required to resolve the constraints identified out to 2050 in the Expected Decarbonisation scenario in Table 9-54. The figure highlights that the LV networks that currently have no capacity headroom require $58.5m in reinforcement, with another $5.8m required for networks that are expected to become constrained by 2025. The period from 2026 to 2030 requires little reinforcement, highlighting that the majority of networks have sufficient capacity to supply the forecast EV and gas transition growth until 2031.



	2023	2024-25	2026-30	2031-35	2036-40	2041-45	2046-50	Discounted present cost of all years
Total	58.5	5.8	0.5	59.9	54.1	68.1	86.7	171.8
11 kV extension	6.4	0.0	0.0	2.3	2.9	2.1	0.7	9.9
400 V underground	6.0	0.7	0.5	6.3	6.4	15.6	24.0	26.6
400 V overhead	0.9	0.0	0.0	0.6	0.9	1.7	2.8	3.1
Transformer	45.2	5.1	0.0	50.7	43.8	48.7	59.2	132.2

Figure 9-44 Forecast LV Reinforcement CAPEX to 2050

Table 9-57 provides the forecast capital expenditure relating to LV capacity constraints during the DPP4 regulatory period. This CAPEX includes:

1. $64.8m resolving existing and imminent constraints shown in the years 2023 to 2025 in Figure 9-44, plus the small number of constraints occurring from 2026 to 2030. The current DPP3 allowances (which were set by WELL's 2020 AMP) do not provide for any LV reinforcement, so this must be funded in DPP4. This expenditure is smoothed over the first four years of DPP4.
2. $12.0m resolving constraints forecast to occur in the 2030/31 regulatory year shown in Figure 10. Capacity needs to be built before these constraints bind. It is assumed that projects to increase the capacity of the LV network can be delivered in a relatively short timeframe and therefore, the expenditure to resolve the 2030/31 constraints is forecast to occur one year prior, in the 2029/30 regulatory year.

Asset Type	2025/26	2026/27	2027/28	2028/29	2029/30	Total for DPP4
Distribution Transformer	12.6	12.6	12.6	12.6	10.1	**60.5**
400V Overhead Line	0.2	0.2	0.2	0.2	0.1	**0.9**
400V Underground Cable	1.8	1.8	1.8	1.8	1.3	**8.5**
11kV Extension	1.6	1.6	1.6	1.6	0.5	**6.9**
Total	**16.2**	**16.2**	**16.2**	**16.2**	**12.0**	**76.8**

Table 9-57 Low Voltage Reinforcement Capital Expenditure Forecast for DPP4 by Asset Type ($K in constant prices)

Table 9-58 details the expected expenditure associated with LV constraints by asset category for the planning period covered by this AMP. This expenditure is included in the total System Growth expenditure summarised in Section 9.8.

Asset Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Subtransmission	-	-	-	-	-	-	-	-	-	-
Zone Substations	-	-	-	-	-	-	-	-	-	-
Distribution Poles and Lines	-	200	200	200	200	100	100	100	100	100
Distribution Cables	-	3,400	3,400	3,400	3,400	1,800	1,800	1,800	1,800	1,800
Distribution Substations	-	12,600	12,600	12,600	12,600	10,100	10,100	10,100	10,100	10,100
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets	-	-	-	-	-	-	-	-	-	-
Total	**-**	**16,200**	**16,200**	**16,200**	**16,200**	**12,000**	**12,000**	**12,000**	**12,000**	**12,000**

Table 9-58 Low Voltage Reinforcement Capital Expenditure Forecast by Asset Category ($K in constant prices)

9.8 System Growth and Reinforcement Summary for 2024-2034

From the details in the sections above, WELL's total forecast capital expenditure for system growth and security of supply for 2024 to 2034 by asset category is summarised in Table 9-59.

Asset Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Subtransmission	439	-	42,890	15,000	-	15,000	-	14,000	-	-
Zone Substations	-	6,000	107,691	90,000	54,000	-	50,870	-	-	-
Distribution Poles and Lines	-	200	200	200	200	600	100	100	100	100
Distribution Cables	2,280	45,398	22,288	41,088	90,378	100,753	5,101	23,264	7,122	5,792
Distribution Substations	-	12,600	12,600	12,600	12,600	10,100	10,100	10,100	10,100	10,100
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets	-	-	-	500	-	-	-	-	-	-
Total	**2,719**	**64,198**	**185,669**	**159,388**	**157,178**	**126,453**	**66,171**	**47,464**	**17,322**	**15,992**

Table 9-59 Capital Expenditure Forecast by Asset Type ($K in constant prices)

Section 10

Enabling the Future Network

10 Enabling the Future Network

This section looks beyond traditional network investment to discuss the new tools and capability that WELL needs in order to deliver decarbonisation-related demand. This includes tools to support a future Distribution System Operator (DSO) function. WELL's systems will evolve gradually with an initial focus on developing tools to assist in connecting the rapid uptake of DER and to incorporate flexibility services into WELL's demand management response.

10.1 Innovation Practices

WELL's desired outcome from its innovation workstreams is to reduce the impact of DER on the network peak demand, delaying capital investment and therefore reducing the rate of electricity price increases for its customers.

Success for these innovation practices is defined by them:

- Being proven to meet the network use case;
- Being proven to be commercially attractive for participants, and
- Having a lower lifecycle cost than traditional network expenditure.

If this can be proven by the trials, then subsequent commercial adoption depends on the availability of allowances to allow WELL to fund the practice.

WELL collaborates with other companies in industry forums, for example through its leadership of EV Connect (see Section 10.3.1.1) and its participation in the FlexForum (see Section 10.3.1.2). WELL is directly engaging with other EDBs and companies through commercial trials that are underway. WELL believes that collaboration with other companies across the electricity supply chain is essential for realising the desired benefits, by producing efficiencies and stacking value for customers.

A significant component of innovation activities is developing tools for the acquisition and analysis of information required to identify and predict network constraints, particularly metering data to indicate the performance of the low voltage network. The accurate targeting of innovation practices at constraints will be critical for meeting their success criteria. Information will be sourced in a coherent and efficient manner when a workstream is established to explore the relevant use case.

10.2 Transformation to a Distribution System Operator

With the increase in DER, the Distribution Network Operators (DNOs) will need to manage the LV network so that it stays in balance and remains a secure system. A DSO platform is expected to be needed to provide the tools and processes to coordinate DER access to the network so that any congestion can be managed within reliability and quality limits, and within network constraints.

While EDBs are not the only candidate to be the DSO provider, they are best placed to understand and manage local technical electricity supply issues and set technical standards governing the connection of DER to the network. EDBs are currently responsible for maintaining power quality under the Electricity (Safety) Regulations 2010. EDBs will be unable to manage power quality in an environment where another party is orchestrating the management of DER on their network, and therefore accountability for voltage and other aspects of power quality must ultimately sit with the DSO.

Figure 10-1 outlines the functions required to manage high levels of DER connecting to the LV network.

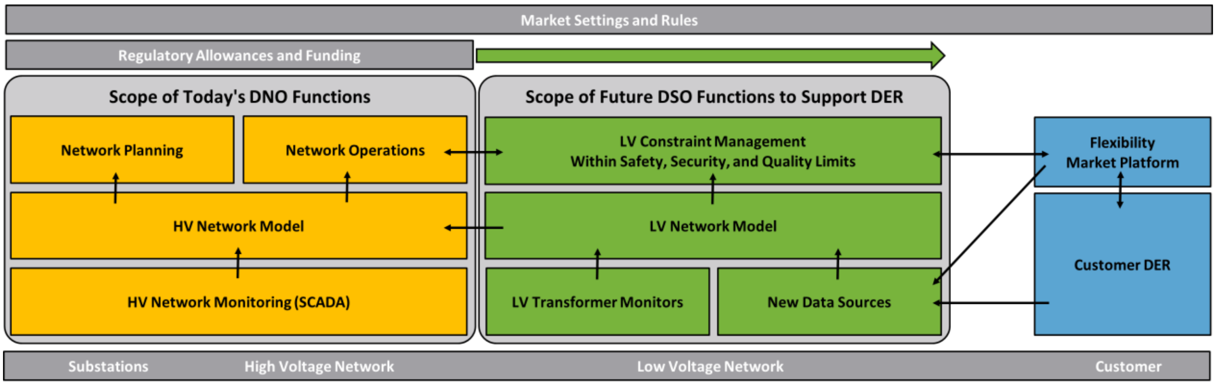


Figure 10-1 Functions Required to Support High Levels of DER

WELL is running a series of workstreams to trial the management of DER, to develop the tools, resources, and commercial arrangements that will best deliver future energy requirements. WELL's sister companies in Australia have taken five years to develop their own DSO capability. WELL's development plans reflect the long development timeframes, with the initial focus being on participating in the sector's development of flexibility services and developing a basic LV visibility and management capability.

10.3 Development Programmes

10.3.1 Supporting Regulatory Changes

Electricity distribution services are regulated directly by both the Commission (who set funding levels and quality targets) and the Authority (who sets market participation rules) and are also subject to indirect regulation by entities like EECA who set standards for the operation of customer appliances. Important regulatory changes are needed to support EDBs' delivery of decarbonisation related investment, developing a DSO capability, and the promotion and incorporation of flexibility services.

10.3.1.1 Changes to Price/Quality Regulation

Like EDBs, price/quality regulation has been designed to support a steady-state electricity distribution network, which is primarily focused on maintaining current quality levels and delivering modest network growth. The regulatory mechanisms are focused on cost efficiency and use historical information to set allowances and quality targets. Regulatory settings now need to evolve, along with EDB asset management practices, to deliver a step change in investment and new customer distribution services. This is discussed in Section 4.

WELL participated in last year's Input Methodology review. The Input Methodology review provided important new tools for managing investment uncertainty, including expanding the reopener mechanism to capture a wider range of unforeseen investments and introducing a large customer contract mechanism.

WELL is also participating in the Default Price Path (DPP) reset process which provides allowances and quality targets for the 2025 to 23030 regulatory period. The DPP reset Issues Paper consultation highlighted changes needed to support the step change in decarbonisation-related investment which include:

1. **Allowances to build new capacity:** Providing EDBs access to new allowances to build new capacity. Most EDBs are signalling they will need to increase their network investment in order to maintain quality standards.

2. **New opex allowances**: New opex allowances are needed for the faster-than-inflation cost increases networks have experienced during current regulatory period. They also need new allowances to allow them to scale up their delivery capability. For WELL, this includes the development of the PMO office functionality to manage the outsourced works tender process. It also includes additional asset planning, customer, cyber and IT and pricing and finance resources to support the delivery programme.

3. **Low voltage management and flexibility services**: New allowances are needed to develop a low voltage management function that will allow EDBs to securely connect new customer loads and to use flexibility services. This will require allowances to purchase new software, purchase data and resources to operate the tools.

   New allowances are also needed to purchase flexibility services as a non-wire alternative.

4. **Ability to adjust Quality targets:** The step change in demand and the associated network reinforcement works programme will impact an EDBs ability to maintain quality:

   a. Planned quality targets will have to increase to reflect the increase in the works programme. Traditionally panned quality targets are set using historic targets based on a business-as-unusual capital programme. However, the step change in investment cannot be completed without a subsequent increase in planned outages.

   b. If demand increases faster than new capacity can be build and/or flexibility services can free up capacity, then unplanned outages are likely to increase as the network operating limits are exceeded.

   Networks will need the ability to adjust their quality paths to reflect the impact the step change in demand and work programme will have on quality.

The purpose of Part 4 of the Commerce Act 1986 includes a specific requirement to incentivise suppliers to continue to invest in distribution networks. This will be especially important as New Zealand delivers its Emissions Reduction Plan which will require EDBs to invest $22b[43] in new capacity in this decade. The Commission's Trends in Local Lines Companies Performance[44] shows that networks have been earning a return less than WACC for the DPP2 and DPP3 periods. Part of the reason for the suboptimal returns is that EDBs aren't getting the allowances they need and they are incurring IRIS penalties for overspending. The DPP reset must provide suppliers with the allowances they need and the expectation of a real return so that they will continue to invest in distribution networks.

[43] Section 3.5, Boston Consulting, Future is Electric, https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf

[44] Page 42-43, https://comcom.govt.nz/__data/assets/pdf_file/0018/230517/Trends-in-local-lines-company-performance-13-July-2022.pdf

10.3.1.2 Changes to Electricity Act and the Electricity Code

Section 4.2.2 highlighted the important role flexibility services will play in ensuring networks can maintain a secure supply of electricity. Section 4.2.2 highlighted that there were two sets of changes needed:

1. Changes to support the rapid uptake of large DER (devices that are larger than LV networks were designed to host) before flexibility services have been developed to the scale needed.

2. Changes to support the development and operation of an enduring flexibility service.

Important changes to the Electricity Code are needed to support each of these steps.

Code changes to support the rapid uptake of EVs (before flexibility services are established)

Changes are needed to the electricity code to support the secure connection of large DER:

- A requirement for all large DER to apply to connect to a network. The assessment process would be automated so as not to slow the connection process and would identify where EDBs would need a more in-depth assessment to ensure the devices can operate within the existing network capacity or whether a flexibility service is needed to manage its operation.

- Strong incentives or standards to ensure DER devices are capable of being remotely managed and can participate in flexibility services.

- Very strong incentives or mandatory rules to ensure that large DER are participating in a flexibility service. EDBs need to be able to rely on flexibility services to ensure the simultaneous use of large DER does not impact network security.

Code changes to support flexibility services

Further changes are needed to the Electricity Code to support the development and operation of a full flexibility service:

- Providing EDBs with streamlined access to smart meter data (both consumption data and power quality data) and information on the location and operating characteristics of large DER. This data is needed as an input into the ADMS systems that are needed to manage congestion on the LV network. The collection and supply of metering data is a natural monopoly, and therefore requires careful regulation to ensure that the cost of its provision to EDBs (which will ultimately be paid for by the customers, who have already paid for its initial collection) is reasonable.

- Implement an industry-wide hierarchy of needs. Network operators (EDBs and Transpower) have been able to maintain a secure electricity system by having priority access to hot water ripple control in emergency situations – emergency situations being when direct intervention is needed to 'keep the lights on'. Currently the Electricity Code provides this capability for hot water ripple control via the DDA. These are rare events that would have a limited impact on competing flexibility services. This capability needs expanding to devices managed by flexibility provides not currently captured in the code. This capability will ensure a stable and secure electricity system that flexibility services can be built on.

- Consideration of the regulatory settings needed to support a DSO. As flexibility services are used more extensively and services are provided up and down the electricity system, their use will need to be co-ordinated so as to maintain the whole of system security. Central to this will be establishing a clear hierarchy of needs or services that the electricity system can use to prioritise and co-ordinate multiple purchasers/users of flexibility.

Note, WELL does not believe that whole-of-system coordination using a central controller of the end-to-end network will allow networks to maintain accountability for their quality performance. Networks have regulatory quality targets applied under Part 4 of the Commerce Act 1986 (SAIDI and SAIFI targets) and power quality obligations under the Electricity (Safety) Regulations and the Code (including ensuring that voltage at the point of supply remains within 6% of its nominal value). EDBs must retain the ability to manage network security to meet the regulatory obligations that they are accountable for.

10.3.1.3 Other Regulatory Changes

WELL believes that equipment standards may be required to be updated to ensure that DER can participate in flexibility services. Experience in Australia has shown that it is cost prohibitive to retrofit devices to make them 'smart' to the extent that they are capable of being externally managed and can communicate with a flexibility provider's management platform.

WELL also believes that common communication standards for flexibility providers management platforms will be needed. Common communication protocols will allow all flexibility providers to communicate with flexibility purchasers.

10.3.2 LV Management and the DSO

As highlighted above, WELL will not need the full DSO capability immediately and can develop each component over time as it is needed. The immediate focus is on developing LV visibility using a low voltage Advanced Distribution Management System (ADMS) which combines GIS spatial data with ICP level consumption and voltage data and transformer monitoring information. WELL's current hypothesis is that less expensive ICP data can be used to build up a general picture of the LV network, and expensive but more accurate transformer monitoring equipment will be installed in congested parts of the network to provide additional intelligence.

10.3.2.1 ANSA LV Constraint Risk Modelling

WELL commissioned ANSA in 2023 to develop a low voltage constraint risk and capex forecasting tool. The tool analysed WELL's residential LV network, combining GIS data, consumption data, decarbonisation load growth forecasts, and standard costs, to forecast LV constraints and the CAPEX required to resolve them over a 50-year horizon. The output of this tool has been incorporated into WELL's System Growth CAPEX forecast presented in this AMP.

This ANSA tool and its findings are discussed in Section 9.7.

10.3.2.2 Future Grid Pilot

During 2022, WELL participated with seven other EDBs in Ara Ake's New Zealand Decarbonisation Challenge. This was focused on identifying potential solutions, both from New Zealand and internationally, for incorporating flexibility into EDB's asset management processes.

With the increase in electrification and increased deployment of DER within the network, greater visibility of the LV network is becoming more important for both planning timeframes and real-time operations. Increased LV visibility will help EDBs identify network constraints, enable proactive identification and resolution of power quality issues, and form the basis for any future market for flexibility services. All of these use cases will provide significant benefit to customers.

As a result of the Challenge, WELL chose to partner with Future Grid. Future Grid is a low voltage network visibility and management tool, which WELL identified as being a good fit to help resolve LV network information gaps, including constraint mapping and modelling the impact of flexibility services on network operations. A pilot of Future Grid ran during 2023. The findings of the trial were:

1. Third party ICP consumption data and WELL's spatial data were successfully incorporated into the tool.

2. Half hour consumption data was able to provide useful asset management insights, however having cost-effective access to voltage data is critical for the majority of use cases for the tool.

3. It is essential for regulation to provide for the ongoing funding of software, data procurement, and people to run and maintain it.

WELL's next steps will be to use the experience of the Future Grid pilot to develop a set of requirements for the procurement of a network-wide LV management tool.

10.3.2.3 Leveraging the Research and Development of WELL's Sister Companies

WELL's sister networks, United Energy (United) and South Australia Power Networks (SAPN) have been developing a DSO capability over the last five years. Their development programmes have highlighted the complexity and time it takes to develop the DSO functionality and the supporting tools needed. WELL is leveraging their knowledge and experience to design its own research and development programmes. This includes engaging with Future Grid, who has been working with both United and SAPN on their DSO development. Important lessons include:

1. Expect a large data correction and cleansing element. The Australian deployment of LV management software like Future Grid highlighted errors in the underlying GIS and ICP data.

2. Expect a multiple year development timeframe. Incorporating the DSO capability into network management functions is complex and will need to be staged.

10.3.2.4 Developing Access to Data

The trial of the Future Grid software focused on whether the software can be connected to the various data sources and whether those data sources provide the information at the level of quality needed. This required the development of data agreements and the handling of large third-party data sources:

1. The quality of ICP and GIS data has been tested as part of the Future Grid trial.

2. A Data Security Policy has been developed that meets the Electricity Code's Data Agreement requirements.

3. WELL is working with retailers to get agreements in place for the provision of consumption data.

4. Lobbying the Commerce Commission for the inclusion of new allowances for the purchase, storage, and analysis of ICP data.

10.3.2.5 Trialling Transformer Monitoring Equipment

WELL is currently considering the most effective and efficient combination of data to provide visibility of the LV network. The currently hypothesis is to support ICP level consumption and quality data with data from transformer monitors spread across the network and focused where the network is congested. The monitoring data would be used to validate the ICP information and to provide better visibility of network constraints.

WELL is trialling different monitoring technology. The trials results will be used to select standard monitoring equipment and to confirm the LV visibility hypothesis.

10.3.3 Scaling Up Delivery Capability

WELL is developing new capabilities to deliver the step change in investment.

10.3.3.1 Project Management Office (PMO)

WELL is sized and structured to deliver its historical maintenance and capital programmes. The business will need to rapidly adapt to the size and volume of the work now being forecast and manage the risks that this work programme will bring. WELL's strategy is to scale up its external service providers who deliver the design and construction services needed to complete this programme and to scale up its ability to efficiently manage these projects internally. WELL is developing a Project Management Office (PMO) that will manage the outsourced project management of large projects. The outsourced work packages will include end-to-end design and construction. Coupled with this WELL is engaging with a broader range of electrical contractors to enable them to build the skills and teams necessary to deliver the work plan.

10.3.3.2 WELL Supporting Overhead

WELL will need to move its internal overhead support from a 'business as usual' footing focused on the replacement of ageing assets, to support the step change in new capacity. This includes (but is not limited to):

- Developing a PMO office function to manage the outsourced delivery of the future work programmes.
- Increasing the capacity of the network design function to build and manage the network blueprint that the outsourced delivery programme can be built around.
- Developing an LV management and DSO function to manage DER connections and incorporate flexibility services into the demand management response.
- Increasing the capacity of the network integration function, combining and managing replacement and growth programmes.
- Developing a network delivery function that will optimise the investment programme, including considering long-term cost efficiency.
- Expanding the procurement and resource planning functions to ensure efficient cost inputs.
- Expanding the connections team to manage DER applications.
- Expanding the existing finance and commercial functions to support the larger work programme.

- Development of a data collection, management and analytics function.

10.3.3.3 Delivery Resources and Supply Chains

WELL is considering how it can standardise its design standards to allow procurement synergies with other networks. Combining procurement programmes could also help to secure access to equipment supply chains. This capability will also be dependent on developing a strong future planning function, allowing the development of a forward procurement schedule.

WELL's focus on delivery resources is on ensuring outsourced resources availability – encouraging large new delivery resources to tender for large design and build work packages. WELL will also consider how it can align its work programmes with other networks. For example, there may be opportunities to move delivery resources from other networks once their programmes have been completed, to help manage the overall demand for contracting resources.

10.3.4 The Development of Flexibility Services

WELL has been considering how it might use flexibility services in the future. Consideration of the potential use cases is being used to direct its development plans. Flexibility services can be categorised by the types of response that they can potentially provide.

- Services that provide a preventative response, shifting demand before a network becomes congested. include price signals and equipment like static chargers that influence and shape customers' behaviour to encourage electricity use during off peak periods. These services provide a preventative response, shifting demand before a network become congested.

- Services that can be used to shift load, to provide a corrective response when demand is approaching the network limits.

- More complex services that can offer an optimised service, changing demand in response to dynamic network conditions.

- Services that can shed load in an emergency. These are a last resort type of service when immediate action is needed to maintain network security.

These service types are summarised in Figure 10-2.

Response	Response type	Use
Shape	Preventative	Influencing behaviour – energy used when network is forecast not to be congested
Shift	Corrective	Controlled response for demand that can be shifted
Shimmy	Optimise	Demand can't be shifted – fit demand within changing constraints
Shed	Emergency	Demand must be shifted to maintain supply

Figure 10-2 Flexibility Service Types

WELL has been considering a combination of different response types and types of services it might need on the Wellington network. WELL's initial thinking on the types of flexibility services that will provide the most value are summarised using in the framework provided in Figure 10-3. The services are categorised by the response type (horizontal axis) and by the type of network constraint the service will be targeted at (i.e. network-wide services like the current hot water control down to an ICP level response where a customer operates within an operating envelope[45]).

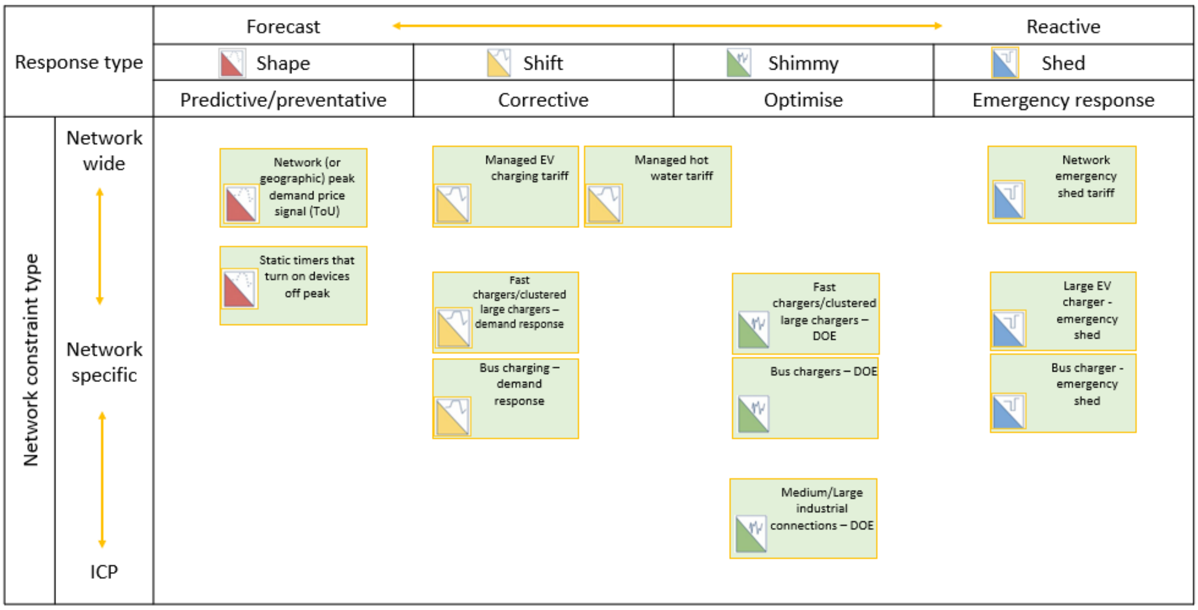


Figure 10-3 Flexibility Service Applications

WELL will focus its trials on the services that will provide the most value, such as services that focus on EV charging and hot water heating, as these are the most effective way of shifting electricity while having a

45 An operating envelope provides the limits that a customers electrcity use must stay within.

minimal impact on how customers want to use their devices (as discussed in Section 4.2.2.2). A combination of services will be needed, including network-wide price signals that will reduce peak demand overall, and services targeted specifically at constrained parts of the network. WELL's trials will target these services that provide the most value.

10.3.4.1 EV Connect Roadmap

EV Connect is an industry-wide work programme that focuses on how more energy can be delivered through the existing network. This is part of an Energy Efficiency & Conservation Authority (EECA) LEVCF project. The purpose of EV Connect is to support EV adoption while maintaining network security.

WELL collaborated with its technology partner GreenSync to develop a roadmap of the industry changes needed to support the introduction of EVs and to offer managed EV charging flexibility services, with the input of 50 key stakeholders provided via workshops and consultations. Stakeholders included policy advisors from the Ministry of Business, Innovation and Employment (MBIE), other EDBs, Transpower as the national grid operator, regulators (the Commission and EA), electricity retailers, consumer advocates, and EV user groups.

Changes outlined in the EV Connect Roadmap include ensuring regulation and policy supports the action needed to connect EVs and that networks operators are appropriately funded. The Roadmap highlights the need for flexible regulation that allows stakeholders to test and develop new services without creating barriers that restrict or slow progress. For example, regulation is needed to ensure customer devices have the right technical specification to participate in the future flexibility services. The Roadmap is summarised in Figure 10-4.

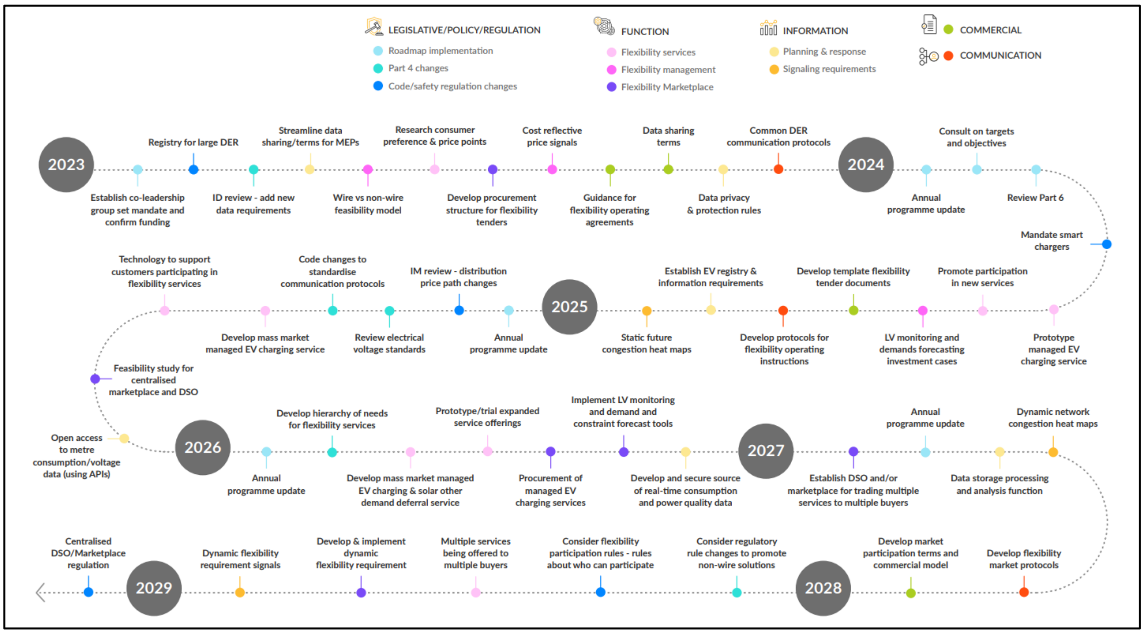


Figure 10-4 EV Connect Roadmap[46]

WELL is focused on implementing these Roadmap actions.

[46] https://www.welectricity.co.nz/about-us/major-projects/ev-connect/

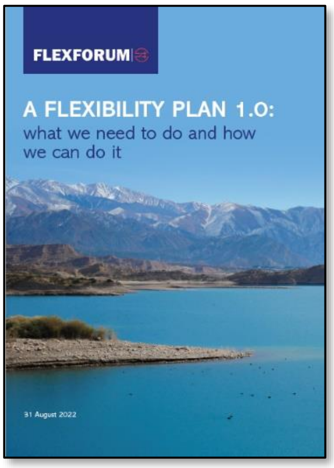
10.3.4.2 FlexForum

The FlexForum is a cross-industry group formed in February 2022 to identify the actions needed to integrate DER into the electricity system and markets to maximise its benefits for New Zealand. The purpose of the group is to:

"Identify the practical, scalable and least-regret actions needed to integrate distributed energy resources (DER) into the electricity system and markets to maximise the benefits for Aotearoa New Zealand".

The FlexForum is the natural progression of WELL's EV Connect programme and is implementing the actions identified by the EV Connect programme. WELL is an active participant and supporter of the FlexForum.

Practically, an immediate outcome of the programme will be trials that can be scaled into operational solutions. The intent is for the Flexforum members to develop trials together – the membership representing flexibility providers with access to controllable customers devises, retailers with the ability to develop scalable customer products and flexibility service users (EDBs, Transpower etc) who will develop their internal processes and systems to use the services.



The FlexForum released the first edition of its Flexibility Plan in August 2022. More details about the FlexForum and the Flexibility Plan can be found at https://flexforum.nz/.

10.3.4.3 EV Connect Technology Trial

The EV Connect programme included a trial to test the capability of the technology needed to manage EV charging on behalf of EV owners, or for owners to receive this as a market service. The technology tested included a digital platform to manage the registration of DER and the aggregation and management of those devices. The trial also tested EV management technology that allows a platform to communicate and manage an EV charger. The trial highlighted the importance of having a central platform to aggregate and manage EV chargers, and the need for those platforms to have a common communication protocol to allow EDBs to communicate when services are needed.

10.3.4.4 Resi-Flex

Resi-Flex is a collaboration between WELL and the Christchurch EDB Orion, to develop and trial commercial mechanisms that support residential flexibility. The goal is to produce a simple and attractive customer proposition for households that rewards customers for shifting their electricity use.

The benefits of doing this collaboratively are that it increases the scale of the trials, pools resources and expertise to allow faster implementation, and produces a consistent approach across EDBs. Figure 10-5 provides a summary of the trial steps.

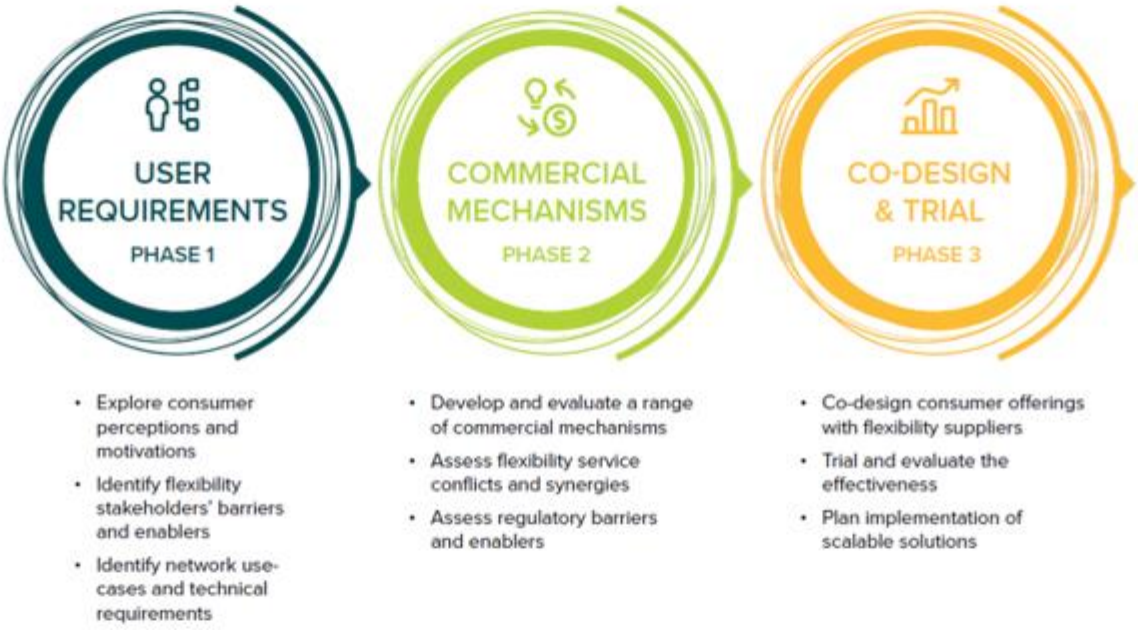


Figure 10-5 Resi-Flex Project Stages

The User Requirements phase of the project was completed in 2023 and the results were presented at the 2023 Electricity Engineers' Association conference, where it won best paper. The findings from the User Requirements phase have been shared publicly in the project's first public report which can be found at https://www.welectricity.co.nz/news/document/323. The second phase, the development of commercial incentives, has nearly been completed with the development of a Commercial Framework which has been used to develop a set of three commercial mechanisms to be trialled in phase three (Co-design and Trial). The Commercial Framework has been passed onto the Electricity Networks Aotearoa Future Network Forum, which will be using it for their commercial flexibility workstream.

The third and final phase is now underway. In March 2024 an Expression of Interest was released to find a trial partner. We are looking to co-design trials in partnership with flexibility stakeholders (e.g., retailers, flexibility suppliers, aggregators, end-consumer integrators, or a mix of actors partnering together). Through the trials, we aim to test a range of commercial mechanisms and consumer offerings that will incentivise greater use of flexibility resources in the future and help stimulate the flexibility market.

10.3.4.5 Flexibility Commercial Framework

As part of the Resi-Flex project, WELL and Orion have developed a commercial framework for flexibility services. This includes a framework for deciding when flexibility services will provide a viable alternative to traditional services and how much an EDB can pay for purchasing flexibility services. The framework will also provide a range of different commercial models that EDBs could offer to flexibility providers. Figure 10-6 summarises the components of the commercial framework being developed.

Figure 10-6 Flexibility Commercial Framework

The commercial framework includes methodologies for calculating and setting flexibility price signals and a calculator for calculating the value of flexibility payments. The framework also includes a selection of different commercial mechanisms. Figure 10-7 summarises the mechanisms and classifies them by the three methods of trading flexibility.

Figure 10-7 Flexibility Commercial Mechanisms

WELL will be sharing the commercial framework in the next public report.

10.3.5 Tariff Pricing Reform

WELL is revising its tariff structure to provide stronger and clearer price signals to encourage off-peak electricity use. The pricing framework its new tariffs are being built around also supports tariffs for flexibility services, including tariffs for managed services. WELL's Pricing Roadmap provides details about the price reforms and can be found at https://www.welectricity.co.nz/disclosures/pricing/future-pricing/.

Specific changes being made to support a network-wide flexibility service (those on the top row of Figure 10-3) include:

- Introducing a new long-run marginal cost methodology that will more accurately calculate the strength of a tariff price signal. This is likely to result in a stronger price signal and incentives for customers to participate in flexibility services. This year we increased the residential ToU price signal from 5c to 8c a kWh, a 60% increase in the strength of the price signal.
- Simplifying WELL's price structures so there is just a peak demand price signal, removing the off-peak price signal. This will provide a clearer signal of the value of flexibility. The remaining costs of operating the distribution network will be recovered through a fixed price component.
- Introducing new tariffs for managed services, similar to those that exist for hot water ripple control.
- Continuing to encourage the uptake of ToU prices. 75% of residential customers are now applying ToU prices. This year we have simplified our ToU prices by combining our EVB and residential ToU tariffs to make it easier for retailers and consumers to use.

10.4 Summary of Future Network Investment Plan

WELL has currently a strong focus on research and development to test new technology, to understand its ability to reliably meet network needs, and to establish commercial frameworks for its employment. This work is operational expenditure that is not funded by the DPP3 allowances.

As flexibility services are operationalised, there will be ongoing operational expenditure for the metering data and transformer monitoring necessary to support their employment, and licensing software to analyse the data..

There may also be an ongoing cost to purchase flexibility services. This will depend on whether services are purchased from an IRIS substitution of CAPEX savings or whether networks are provided with a direct OPEX allowance. At this early stage in the development of these services, it is assumed that they will be funded by substituting CAPEX savings. This also reflects the difficulty in forecasting an OPEX allowance that will depend on the specific details of each CAPEX deferral (i.e. this will depend on the aggregated value of the CAPEX being deferred and the length of the deferral). Conversely, funding flexibility by CAPEX substitution will mean that the savings will always be relative to the CAPEX being deferred. For CAPEX/OPEX substitution to work, the IRIS needs to be adjusted so that inter-regulatory period benefits can be recognised. The current IRIS does not provide offsetting CAPEX savings if the OPEX is incurred in one regulatory period and the CAPEX saving is in the next because future allowances will already include the impact of deferring the CAPEX and there will be no IRIS benefit to offset the initial IRIS penalty.

WELL's delivery strategy also assumes the development of a project management office, and data analytics and procurement functions. Additional resources have been added for these functions. WELL will also need to increase the capacity of its existing non-network overhead functions to support the doubling of the size of its network investment programme.

10.4.1 Change in OPEX Costs to Support the CAPEX Programme

Table 10-1 provides the change in operating costs to the base year, separating step changes or new functions, and growth in existing functions needed to deliver the programme increase (network scale growth).

Regulatory Year Ending	Mar-26	Mar-27	Mar-28	Mar-29	Mar-30
Increases in Existing Functions (Scale Growth)	1,179	1,581	1,661	939	512
Step Change	8,216	8,767	9,401	10,130	10,968
Total	**9,394**	**10,347**	**11,062**	**11,069**	**11,480**

Table 10-1 – Change to Base Year (Regulatory Year Ending March 2024)

10.4.1.1 Forecasting Scale Growth – Changes from the 2023 base year

For WELL's existing delivery functions, those of a transactional nature that flex with workload, cost drivers have been used to forecast change in operating costs from an increasing work programme. Table 10-2 summarises the roles that will scale with the increasing capex programme and network size, and the cost driver used to forecast resource changes.

Existing delivery functions	Cost driver	March 2026	March 2027	March 2028	March 2029	March 2030
Quality and Safety Oversight and Audit	Capex programme	203	238	238	168	101
Maintenance delivery	RAB	49	146	195	244	215
Asset planning	Capex programme	732	1,002	1,033	332	0
Admin	Capex programme	195	195	195	195	195
Total		**1,179**	**1,581**	**1,661**	**939**	**512**

Table 10-2 – Increases in Existing Functions ($k)

10.4.1.2 Forecasting Step Changes – Changes from the 2023 base year

As highlighted in Section 4, WELL needs to develop new functions to support the increase in our capex programme and the development of new non-traditional solutions like flexibility services. Table 10-3 summarises the step changes and the forecast method. Note, DPP step change criteria have not been applied to the forecast. The step changes are all of the expected cost increases, irrespective of whether the DPP price path will provide allowances for those costs. A budget for flexibility payments has also not been included. Flexibility payments are difficult to forecast accurately, and it is assumed that they will be funded from innovation allowances.

Step change	Why it's needed	2025/26	2026/27	2027/28	2028/29	2029/30	Forecast methodology
LV operations & data analytics	To provide visibility of the LV network, to incorporate flexibility services and to develop LV quality standards. Note, this includes a data analytics function to collect and analyse meter and smart device data. Note, this function could be outsourced if its more efficient to do so.	1,786	1,786	1,786	1,786	1,786	• Cost quotes for data purchase and software license fee. • Resourcing estimates to provide new functions. • Market salary data.
Field Service Provider uplift	An early market assessment has indicated a step change in tender prices as contracts tied to market inflation are adjusted to reflect above inflationary increases.	2,500	2,500	2,500	2,500	2,500	• Expert advice
Vegetation management	New contract negotiated in 2023	400	400	400	400	400	• Actual contract costs
Insurance	Insurance costs have increased at a historic rate of 15% p.a.	1,300	1,851	2,485	3,214	4,052	• Based on historic average of 15%
Future services development	Distribution services are changing as we consider new non-traditional solutions and rapidly increasing demand. Additional resource to develop future services and our asset management strategies.	304	304	304	304	304	• Resourcing estimates to provide new functions. • Market salary data.
Procurement and contract management	As outlined in Section 4 of our 2023 AMP, we are moving to a procurement model which his bundling projects into large design and build work programmes. Additional functions are to operate this procurement model. Previously our modest capex programme was delivered by our field service provider.	586	586	586	586	586	• Expert advice on new roles needed (four new roles - commercial, legal, procurement and programme admin) • Market salary data.
ESG	Insurers, stock market participation, banks and potentially financial reporting all expect ESG reporting.	464	464	464	464	464	• Executive team representation and Board subcommittee • Market salary data.
Customer communications	As outlined in Section 4 of our 2023 AMP, we expect that we will need more direct customer communications to confirm service levels and to support the promotion of flexibility services.	119	119	119	119	119	• Expert advice on new roles needed. • Market salary data.
Cyber security and IT	To support digitization and increasing cyber threats.	567	567	567	567	567	• Executive team representation • Market salary data.
Finance governance & pricing	New roles to strengthen the management of the growing RAB and to deliver cost-reflective prices. The pricing role includes pricing for flexibility services.	531	531	531	531	531	• Market salary data.
Total		**8,208**	**8,759**	**9,393**	**10,122**	**10,960**	

Table 10-3 – Forecast OPEX Step Changes

10.4.1.3 High Level Benchmarking

As a high-level sensibility check, Table 10-4 compares the total expenditure (expressed as $/ICP) with the other large networks with urban centres and the industry averages. Even with the forecast OPEX increases, the $/ICP metric remains comparable with other urban networks and the industry averages.

Total Opex	Wellington Electricity	Orion NZ	Vector Lines	Aurora Energy	Average All EDBs	Average Non-Exempt
2023	220	345	254	524	382	437
2026	269					
2030	263					

Table 10-4 - $/ICP Comparison

Section 11

Support System

11 Support Systems

WELL invests in non-network assets to support the distribution of electricity to customers. These assets include information systems, plant and machinery, and land and buildings. This section describes the approach and investment requirements for these systems over the planning period.

11.1 WELL Information Systems

Information Technology (IT) is a key enabler in the distribution of electricity. Information and communication technologies have a pervasive reach and are now impacting every area of the business. There is increasing convergence of traditional engineering and IT disciplines, especially in regard to Operational Technology[47] (OT). Figure 11-1 shows the industry trends likely to impact WELL's IT systems over the next five years. The IT system plans must be able to cater for these.

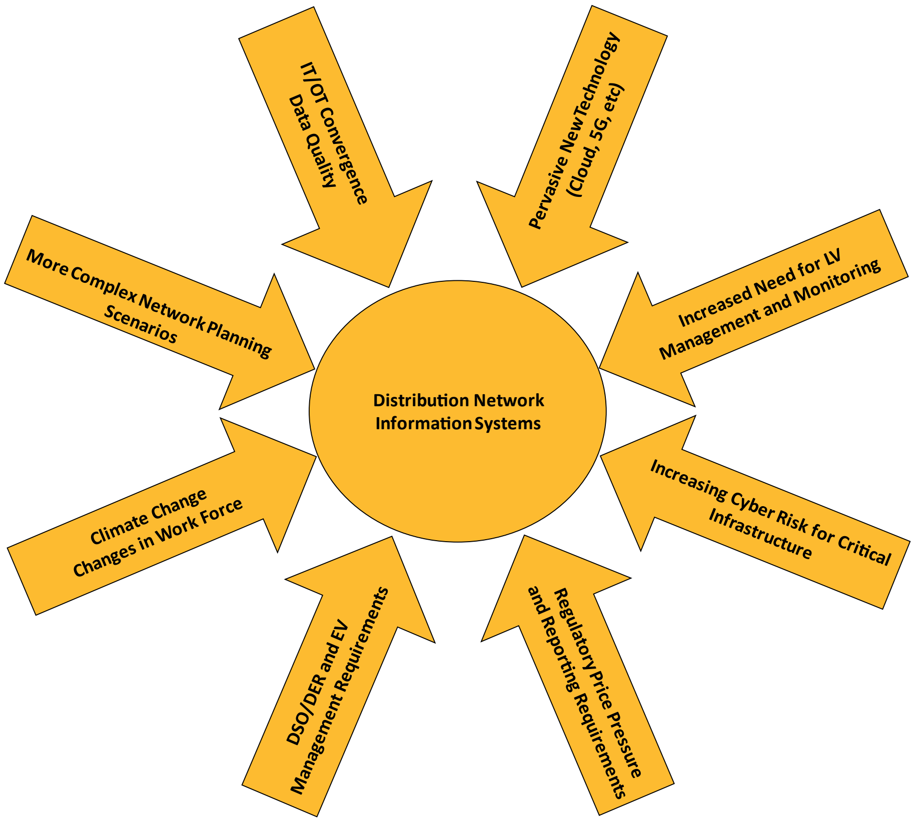


Figure 11-1: Industry Trends Impacting WELL's IT Systems

11.1.1 Asset and Operational Systems

The information systems WELL uses to manage its asset information are described below.

11.1.1.1 SCADA

A GE PowerOn Advantage Supervisory Control and Data Acquisition (SCADA) system is used for real-time operational management of the WELL network. The SCADA system provides operation, monitoring and control of the network at 33 kV and 11 kV. WELL does not have any telemetry feeding the SCADA system

[47] Operational Technology is defined as IT systems that enable the power system to operate.

for the low voltage (LV) network (400 volts or below) but is investigating how this could be implemented as distribution substations are upgraded or replaced.

Outage reports are recorded by the GE PowerOn Calltaker system utilised by the Outage Manager at the WELL Contact Centre. The Calltaker system electronically interfaces with the field service provider's dispatch systems to dispatch field staff for fault response. Closed jobs are also fed back electronically to the Calltaker system. The WELL Contact Centre also updates outage information for publication on the WELL website and outage application.

In 2023 WELL completed the upgrade of its SCADA from PowerOn Fusion to PowerOn Advantage. The upgrade has enabled:

- A more flexible and resilient IT architecture utilising virtual machines;
- Improved cyber security of the solution with the inclusion of Ansible solution for robust rollout of new features and patches for day-zero vulnerabilities.
- Future integration with GIS via common information model adaptor so that LV models can be imported; and
- An upgrade of workstation and server hardware to the latest supported hardware and operating systems.

11.1.1.2 Load Management System

The Load Management System is used for managing hot water load control, and the switching of streetlights and other controllable loads.

In 2023 WELL completed the replacement of its legacy Load Management System master station with Catapult's OnDemand product.

The key benefit of the new Capatult system is that load management system is now a supported platform and less likely to fail at a critical time. It would also provide better control options and better programming / initiation options.

11.1.1.3 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 Electric Office GIS application for planning, designing and operating the distribution system and this is the primary repository of network asset information.

The GIS interfaces to WELL's maintenance management system (SAP PM), the billing system (Gentrack), the field service provider's works management system, and the B4UDig underground asset location platform.

11.1.1.4 Drawing Management System

WELL stores all GXP, substation, system drawings, and historic asset information diagrams in ProjectWise in PDF and CAD format. WELL is currently looking at reviewing the system for building an automated workflow for access and approvals of the drawings.

11.1.1.5 Power System Modelling

DIgSILENT PowerFactory is used to model and simulate the electrical distribution network and analyse load flows for development planning, contingency planning, and protection studies. The PowerFactory database contains detailed connectivity and asset rating information. To ensure ongoing accuracy, the model is manually updated every quarter to include recently commissioned network assets and augmentations. Model updates are regularly distributed to design consultants to ensure consistency for commissioned studies. Additional licenses have been added to Power Factory system to support increased use of the system.

11.1.1.6 Cable Rating Modelling

CYMCAP (cable ampacity and simulation tool) is used to model the ratings of underground cables at all voltages for existing cables in service and new developments.

11.1.1.7 LV Voltage Drop Modelling

LVDrop is used to model LV electrical networks to ascertain voltage drops and the loading of conductors and transformers. LVDrop contains all the relevant cable, conductor, transformer and ADMD information and ratings. It is used for new subdivision reticulation designs and forms part of the customer connections and planning process.

11.1.1.8 Protection Relay Configuration Management Database

DIgSILENT StationWare is a centralised protection setting database and device management tool. It holds relay and device information, parameters and settings files. WELL is currently looking at building an automated workflow for access and approvals of the configuration parameters and moving the database to a secure cloud-based repository.

11.1.1.9 Maintenance Management System

WELL uses the SAP Plant Maintenance (SAP PM) module to plan its maintenance activities and capture asset condition data for both preventative and corrective works. This system allows WELL to issue maintenance workpacks to service providers electronically. Maintenance results are returned electronically via either an integration module (for high-volume tasks), or a web interface (for low-volume tasks). Asset data is synchronised with GIS, which allows maintenance tasks to be grouped spatially to increase efficiency.

SAP PM is currently hosted in Melbourne by WELL's sister company Powercor. WELL is currently exploring options for its replacement.

11.1.2 Billing System

Gentrack is used to manage ICP and revenue data, and GXP reconciliation to deliver billing and connection services. Gentrack is populated and synchronised with the central National ICP registry. It interfaces with the GIS and PowerOn Advantage systems to provide visibility of customers affected by planned and unplanned network outages. Gentrack interfaces with the SAP financial system for billing purposes.

The Gentrack system is currently hosted in Melbourne by Powercor. The billing system requires overhaul and WELL is looking to modernise its billing system with the latest options available.

11.1.3 Financial Systems

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

SAP is hosted in Melbourne by Powercor. WELL is currently exploring options for its replacement.

11.1.4 System Upgrades and Replacement Planning

WELL has initiated a number of significant projects to upgrade or implement core systems. The status of these upgrades is provided in Table 11-1.

System	Status
GIS	Upgrade completed.
HR/Payroll	Upgrade completed.
Billing	Overhaul of the system is planned to modernise the billing solution
SCADA	Upgrade completed.
Load Management	Upgrade completed.
Planned Outage Management	Implementation complete.
Finance/Plant Management	Project scoping is underway.
Contractor Works Management	Project scoping is underway.
Project Management	Project scoping is underway.
Inventory Management	Project scoping is underway.

Table 11-1 Status of Support System Replacement Programme

11.2 Cyber Security

WELL is facing increased cyber security threats in the same manner as all critical infrastructure providers. The energy sector is highlighted as a cyber security target and this threat is only going to increase given the ongoing digitisation of the power utility applications. A cyber security attack on a power utility can have severe consequences affecting the physical network, such as overloading of power systems or erroneous power system operation. WELL is working closely with the National Cyber Security Centre (NCSC) to ensure that its IT systems, especially those relating to the direct control of the electricity network, are as secure as possible. This increased cyber risk means that WELL continues to invest on an ongoing basis in training, systems and processes that enhance cyber security monitoring and protection.

WELL has performed an internal Cyber Security Audit against ISO 27001:2013 and number of improvements have been implemented based on the findings of this report. Another round of audit is planned for 2024 covering operation, governance, and Office 365 configurations.

11.3 Identifying Asset Management Data Requirements

Asset management data requirements are defined in WELL's asset maintenance standards. The asset management data requirements are updated when new needs are identified within the business or through changing regulatory requirements.

Asset management data requirements and processes are also specified in the Field Service Agreement with Northpower who input asset information into the GIS and SAP PM information systems.

11.4 Data Quality

Robust and timely asset information is needed to drive asset management activities such as development, maintenance, refurbishment, and replacement.

Data quality is measured by the data's usefulness for specific purposes and includes the following dimensions:

- **Accuracy:** Data recorded in information systems must be factual, timely, clear, and consistent. Data should be checked at the source whenever possible.
- **Completeness:** All mandatory data in a dataset must be completed. Default codes are used only where appropriate, not as substitutes for actual data. Data should reflect complete capture of all WE* activities, with regular spot checks, audits, and comparisons between systems to identify missing data.
- **Consistent:** All the data items when stored in multiple information systems should be as consistent as possible and have the least number of conflicts.
- **Timeliness:** Timely recording of data is crucial, especially in distribution services, ensuring data is available when needed for service delivery and reporting.
- **Validity:** All the data must be valid and where possible should conforms to the syntax (format, type, range) of its definition.
- **Uniqueness:** All the data items should have least number of duplicate records

Apart from above data quality dimensions following are some characteristics of data those are defined for data managed by each information system and are part of data quality framework.

- **Availability:** All data must be able to be used or obtained where possible
- **Confidentiality**: All data items should be protected against unauthorized access and misuse
- **Responsibility:** All the data information system must have roles and responsibilities assigned for maintaining data quality that is who is responsible, and show is accountable

The GIS is the central repository for WELL's network asset information as shown in Figure 11-2, and it needs to be complete, accurate, and up to date to enable good asset management decisions.

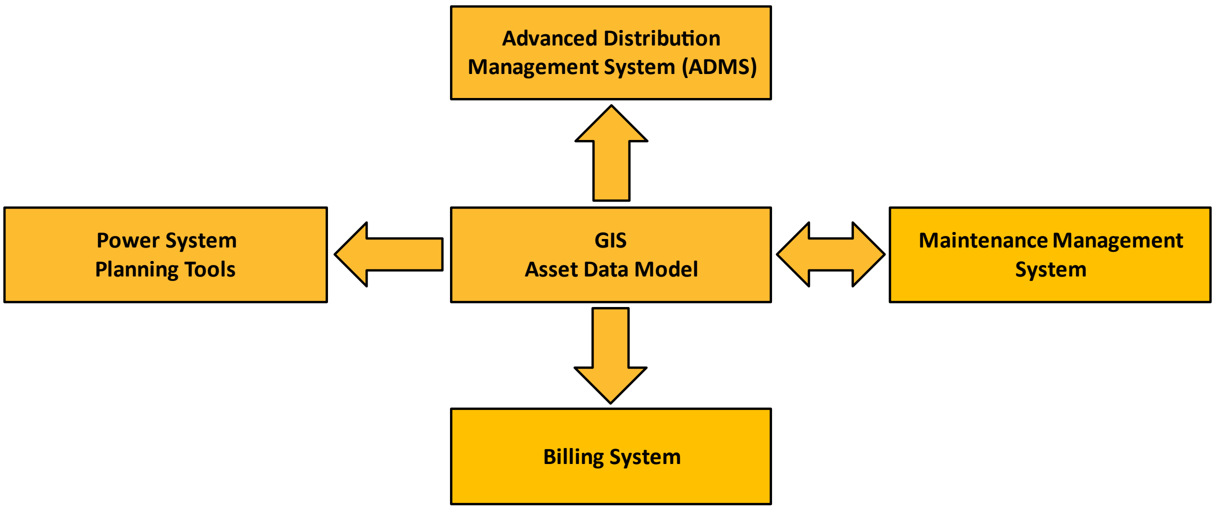


Figure 11-2 GIS Centrality to Asset Data Model

Data management and governance is critical for WELL, particularly with new data requirements emerging as the electricity industry evolves. WELL has completed a review of its data management and is implementing the most important findings of this review and including them in any future system replacements requirements.

11.5 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.

11.6 Land and Building Assets

WELL's primary data centre, corporate disaster recovery site, and backup network control room are located at Transpower's Haywards GXP. Transpower has terminated WELL's lease of the site. The construction of a replacement site is complete, and WELL will complete the relocation of these services to the new location in 2024.

WELL's head office in Petone is located in a tsunami evacuation zone.[48] WELL has commenced planning to relocate its head office away from the coast in order to mitigate this risk. This relocation will occur in 2025/26. There are two potential sites currently under consideration, with one to be selected in early 2024. The project will involve the construction of a new building with seismic performance at Importance Level 4, the relocation of WELL's primary control room to the new building, and development of the associated systems and processes to support modern ways of working.

WELL is investigating options for new strategic storage locations. Storage of spare equipment at distributed locations around the region is a key element of WELL's preparations for responding to a major earthquake. WELL's earthquake readiness is discussed in Section 12.4.2.5.

[48] https://www.huttcity.govt.nz/services/emergency-management/useful-information/maps

11.7 Non-Network Asset Expenditure Forecast

From the details in the sections above, WELL's non-network expenditure forecast is summarised in Table 11-2.

Expenditure Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
GIS	150	150	150	150	150	150	150	150	150	150
SCADA	100	250	250	250	250	250	250	250	250	250
Load Management	-	-	-	250	-	-	-	-	-	-
Operational IT Infrastructure	-	-	-	750	-	-	-	-	-	-
Mobile Operations Tools	-	100	-	100	-	100	-	100	-	100
Outage Management	100	-	-	-	-	-	-	-	-	-
Asset Management	-	560	-	-	-	-	-	-	-	-
Engineering Tools	-	20	100	20	-	20	-	20	-	20
Other Systems (e.g. Billing, Financial, Website)	1,508	1,268	65	590	115	90	665	140	65	90
IT Infrastructure	614	2,245	515	515	785	485	1,785	485	485	525
Head Office Relocation	-	30,000	-	-	-	-	-	-	-	-
Capitalised Leases	2,000	-	-	-	-	-	-	-	-	-
Future Network (From Section 10)	-	2,400	600	600	600	600	200	200	200	200
Total Non-network Capital Expenditure	**4,472**	**36,993**	**1,680**	**3,225**	**1,900**	**1,695**	**3,050**	**1,345**	**1,150**	**1,335**
System Operations and Network Support	10,169	12,336	12,760	13,077	13,080	13,262	13,262	13,262	13,262	13,262
Business Support	12,723	15,434	15,964	16,361	16,365	16,592	17,235	17,942	18,720	19,575
Total Non-network Operational Expenditure	**22,893**	**27,770**	**28,724**	**29,438**	**29,445**	**29,855**	**30,497**	**31,204**	**31,982**	**32,837**

Table 11-2 Non-Network Expenditure Forecast
($K in constant prices)

Section 12

Resilience

12 Resilience

12.1 WELL's Resilience Framework

This section describes WELL's approach and investment plan relating to resilience and focuses on managing and mitigating events beyond normal circumstances and under emergency situations.

As a lifeline utility in accordance with the Civil Defence Emergency Management (CDEM) Act 2002, WELL must ensure that it is able to function to the fullest possible extent during and after an emergency, even though this may be at a reduced capacity. This can include one-off events such as a storm, earthquake, or equipment failure.

The funding of resilience expenditure via the DPP allowances has been challenging, and WELL welcomes the extension of reopener events in the 2023 Input Methodologies review to include reopeners for resilience expenditure. These reopeners provide an avenue for EBDs to seek funding for resilience projects in a more efficient manner than WELL was required to follow for its 2018 to 2021 Earthquake Readiness CPP.

Decarbonisation introduces additional elements to resilience. As the community transitions transportation and heating fuels away from petrol and gas to electricity being the only source of household energy, electricity outages will have a much greater impact than they currently do. Conversely, EVs have the potential to increase household resilience through the use of their batteries to supply critical household appliances.

Any new technologies need to be carefully considered through the lens of resilience before being accepted for use on the distribution network. For example, communication systems that play a critical role in managing the security of the network and its recovery following an event, such as the hot water control system that is used for emergency load shedding, cannot be allowed to fail. The operation of these systems would be placed at risk if they transitioned to new technology that was reliant on cellphone networks, due to the inevitable overloading of cellphone networks that occurs following a major event, and the short battery backup times at cell towers. This vulnerability has been demonstrated by the Christchurch and Kaikoura earthquakes, and again during Cyclone Gabrielle. It is essential that telecommunications network operators, as providers of critical infrastructure, adjust their contingency plans to accommodate the long outages on the electrical supply network that can occur during major events, rather than continuing to optimise their systems for business-as-usual operation.

The WELL resilience framework has been sectionalised in this plan per the following structure:

- Climate change;
- Emergency response and contingency planning;
- High impact low probability (HILP) events;
- Future resilience work – WeLG Regional Resilience Project; and
- The EEA Resilience Guide and Self-Assessment.

A significant amount of work was undertaken to improve earthquake readiness under WELL's 2018 CPP. Delivery of the Readiness CPP greatly improved WELL's ability to respond to emergencies. It is important to note that the focus of the CPP programme was the Readiness area of the 4Rs resilience model, and while this does improve resilience, further work is needed to increase the network's ability to withstand a major earthquake. Section 12.5 discusses additional work that needs to be delivered to further improve resiliency, including improving the single point of failure risk at Transpower's Central Park substation and accelerating the replacement of fluid and gas-filled subtransmission cables.

12.2 Climate Change

Climate change is expected to cause a rise in sea levels as well as changing weather patterns which are expected to result in more frequent and severe storms than have previously been experienced. This will impact temperature, rainfall, and wind within the region as well as the frequency and intensity of storms.

NIWA is forecasting that the climate in the Wellington region will continue changing for the foreseeable future.[49] The average temperature in the region is expected to increase by 0.75-1.25°C by 2040. This increase in average temperature will result in fewer cold days and an increase in the number of hot days, potentially changing the nature of the electricity network load patterns. Rainfall events are expected to become more severe in both frequency and magnitude, increasing the risk of flooding and landslides. 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. Wellington already has one of the highest wind zones in the country due to its position on the Cook Strait and between the mountain ranges of the two islands.

Rising sea levels present a risk in central Wellington where a large number of substations in the CBD are in the basements of buildings. The sea level at Wellington rose at an average of 2.82 mm per year from 1961 to 2019, through a combination of climate factors and seismic subsidence, with the rate of rise continuing to accelerate.[50] Sea level rise is a long-term problem, with significant variations in possible scenarios, and effects becoming significant towards the end of the century.[51] Issues could occur sooner with stronger storms due to warmer seas creating larger storm surges on top of rising sea levels, such as was witnessed during Cyclone Dovi in 2022 and the large storm surges that caused damage on the south coast of Wellington in April 2020 and June 2021.

A coordinated response between local authorities and utilities is required to prepare the region for the impacts of climate change. WELL is making changes to policies and standards to better protect the network from these risks. For example, WELL's Inundation Zones Policy will over time help WELL to better protect assets at risk of storm inundation and sea level rise. To be effective, these changes in standards cannot be made in isolation. Further work with local authorities is required to understand their defence strategies, and to influence District Plan updates, to ensure that WELL's policies and standards are tightly aligned to a coherent plan across the Lifelines Group.

12.3 Emergency Response and Contingency Planning

WELL follows the 4Rs approach to hazard management, as outlined by the National Emergency Management Agency (NEMA).[52] The 4Rs are described in the context of EDBs in the EEA resilience guide as follows:

- **Reduction** – Identify and mitigate network vulnerability risks;

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[49] "Climate change projections for west of Wellington's Tararua and Remutaka Ranges" NIWA, September 2022.
[50] "Update on sea-level rise projections for Wellington City" NIWA, March 2021.
[51] "Sea Level Rise Options Analysis" Tonkin & Taylor, June 2013.
[52] https://www.civildefence.govt.nz/cdem-sector/the-4rs/

- **Readiness** – Pre-event contingency planning and training;
- **Response** – Immediate actions following an event; and
- **Recovery** – Long-term reinstatement of the network.

The mitigation of potential emergency events is supported by a number of plans and initiatives across the business described in the following sections.

12.3.1 Civil Defence

NEMA is responsible for emergency management on a national scale. Emergency management is governed through the CDEM Act 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 emergency management framework.

12.3.2 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.

12.3.3 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 governments. 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 stormwater 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. This has to some extent been alleviated by the Transmission Gully route, as was demonstrated when State Highway 59 (the former section of State Highway 1 that was bypassed by Transmission Gully) was closed for six weeks in 2022 due to a landslide.

Through 2018 and 2019 WeLG conducted a project on regional disaster response and recovery, as discussed in Section 12.5. A key component of this project was the consideration of the interdependencies between lifeline utilities and how these are likely to affect the restoration process. This project involved detailed modelling of the likely damage to each lifeline utility network based on GNS modelling of the Wellington fault and regional geography as well as the economic impact on the region that such an earthquake would have.

12.3.4 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.

12.3.4.1 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 and Kaikoura earthquakes and the Wellington June 2013 storm have been incorporated into these plans.

12.3.4.2 Civil Defence and Emergency Management (CDEM) Plan

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

This CDEM Plan follows the four ‘Rs’ approach to dealing with hazards that could give rise to a civil defence emergency.

12.3.4.3 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.

12.3.4.4 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.

12.3.4.5 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 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 the Haywards DR site and operate from there until the end of January 2017.

WELL is relocating its primary DR site, including its primary data centre, backup control room, and essential business continuity functions, from Transpower's Haywards substation to a new building in Tawa. The new location offers significant resilience benefits, being a fully seismically rated building (100% NBS at Important Level 4) located in a different "island" to WELL's head office in Petone.[53] The relocation project will be completed during 2024.

12.3.4.6 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.

12.3.4.7 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.

12.3.4.8 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.

12.3.4.9 Earthquake Response Plan

The purpose of the Earthquake Response Plan is to ensure that WELL is prepared to respond safely and effectively to an earthquake that impacts the electricity network, with consideration for the probable isolation between different network areas. This involves direction on how and when to activate other associated event management plans as well as directions for the use of the DR sites and access to earthquake-specific equipment and systems including:

- Safe building entry;
- Emergency spares locations and access; and

[53] In the context of resilience, "islands" reflect the expected separation of WELL's network into isolated operational regions following a major earthquake due to damage to the roading network. The three islands are broadly defined as Wellington south of Ngauranga Gorge, Porirua and Wellington's suburbs north of Ngauranga Gorge, and Hutt Valley.

- Mobile substations and data centres.

12.3.4.10 Pandemic Preparedness Plan

The purpose of the Pandemic Preparedness Plan is to manage the impact of a pandemic-related event by:

- Protecting employees as far as possible from the spread of disease;
- Creating a safe working environment; and
- Maintaining essential business functions with reduced staffing levels if containment is not possible.

The Pandemic Preparedness Plan was updated in early 2020 as it became apparent that COVID-19 was going to have a major impact on the operation of the business. The Plan was regularly updated throughout the pandemic as government guidance evolved, and to incorporate best practices learned from WELL's sister companies overseas.

WELL operated with two control rooms in separate locations, alternating shifts between the main control room and DR site to minimise the crossover of controllers. This enabled the control room to operate with a minimum degree of risk through all stages of the pandemic.

The Plan also describes working arrangements for each alert level, with staff being split across two sites to reduce the impact of disease entering the workplace. During elevated alert levels, WELL transitioned to staff largely working from home, with only the network control room and some senior management working from the two operational sites.

12.3.4.11 Other Emergency Response Plans

WELL has other emergency response plans including:

- Priority notification procedures to key staff and contractors;
- Total Loss of Zone Substation Plan;
- Network Spares Management Policy;
- Loss of Transpower Grid Exit Point Plan (Transpower Plan);
- Emergency Load Shedding Plan;
- Participant Rolling 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.

12.4 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. This is managed through IT security policies.

WELL is working closely with the National Cyber Security Centre (NCSC) to ensure that its IT systems, especially those relating to the direct control of the electricity network, are as secure as possible. The increase in cyber risk means that WELL needs to invest in training, systems and processes that enhance cyber security monitoring and protection.

HILP events are unpredictable, generally uncontrollable and prohibitively expensive to avoid, if at all possible. WELL's design standards align with industry best practices 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.

12.4.1 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 projects undertaken with Transpower every 3-4 years 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 response plans have been drawn up to mitigate impacts from such events; and

- **Environmental risk reviews** – understanding and identification of the risk posed by natural disasters such as earthquakes and tsunamis. Studies have been undertaken on behalf of WELL by GNS and other external providers have supported the development of WELL's Storm Inundation Policy.

12.4.2 Strategies to Mitigate the Impact of HILP Events

A discussion on the following HILP events is covered below:

- Major storm events;
- High-impact asset failure;
- Upstream supply failure;
- Major earthquake;
- Flooding and inundation, and
- Wildfire.

12.4.2.1 Major Storm Events

The Wellington region is very susceptible to high winds and severe storms, which have the potential to cause a significant amount of widespread damage to the overhead network. For this reason, WELL uses a relatively high wind loading when designing overhead lines when compared with other network companies. This susceptibility is also a factor in the high proportion of the Wellington network that has been constructed with underground cables.

A major risk of potential outages on overhead sections of the WELL network is lines being struck by vegetation and windblown debris. This is currently managed via the WELL vegetation programme which, as discussed in Section 7.5, has been successful in maintaining the reliability of the network. It can be difficult to protect against strong wind gusts causing vegetation to contact lines that do not normally get close to a line, or where debris has been blown clear of the line before a patrol can be completed.

In June 2013, Wellington experienced a severe storm of a magnitude similar to the “Wahine” storm of 1968. Wind gust speed remained above 100 km/h for approximately 24 hours, peaking at over 200 km/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, predominantly at the low voltage level, affected customers in both rural and urban areas with wind gusts uprooting trees and carrying debris into overhead lines, damaging poles and conductors.

The affected areas were widespread and outages were prolonged as the conditions made it difficult to patrol and repair lines. Blocked roads and traffic congestion resulted in travel time delays. To address the significant workload, 150 additional staff from other regions were brought in to assist with the restoration efforts. Since then, improvements have been made to vegetation management, field crew fatigue management, SCADA system capacity, and capacity to scale up emergency staff in an event.

12.4.2.2 High-Impact Asset Failure

WELL network’s system security standard is designed to provide a security of N-1 at the zone substation level, meaning that each zone can operate at full capacity after the failure of a single asset. This is generally achieved by having dual subtransmission circuits and power transformers. Resilience within the 11 kV network is provided by the use of meshed rings or tie points between radial feeders to minimise the effect of equipment failure and improve the restoration after an event.

Due to the constrained nature of many WELL sites and the subtransmission routes that have been constructed sharing the same route, an event affecting one component has the potential to affect the other and lead to a total outage at that site. This is mitigated through different means depending on the type of asset, such as physical barriers between transformers at most sites, or separation between overhead lines where space allows. Cable route resilience is considered part of the route selection process for new subtransmission cables. WELL’s mobile substations provide another method for restoring limited supply following a major asset failure.

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, though this does not consider potential damage to the distribution network or adjacent zone substations in a major event. The total resupply of a zone substation from a neighbouring zone is not possible for all substations or at all times in the year, as 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. Decarbonisation will exacerbate these limitations as the electrification of loads currently supplied by fossil fuel increases demand and reduces capacity headroom on the electrical network.

Areas that are unable to be supplied in the event of a zone substation outage are mostly at the extreme ends of the network with Wainuiomata, Karori, Mana-Plimmerton, and north of Upper Hutt being the most obvious examples. Two of these substations also supply two of the main water treatment plants providing potable water to the region at Te Marua and Wainuiomata treatment and pumping stations. Both plants have backup power supplies that can cover their emergency requirements but require network supply to operate at full capacity.

12.4.2.3 Upstream Supply Failure

WELL takes supply from Transpower at Grid Exit Point (GXP) substations. There are nine GXPs in the Wellington region supplying WELL at either 33 kV or 11 kV, with some GXPs providing supply at both voltages. Table 12-1 lists the number of ICPs supplied by each GXP that supplies WELL's network.

GXP	ICP Count (2023)
Central Park	49,803
Takapu Road	34,391
Melling	20,579
Gracefield	19,808
Haywards	13,045
Wilton	12,786
Upper Hutt	11,253
Pauatahanui	7,132
Kaiwharawhara	5,594
Total	**174,391**

Table 12-1 ICP Numbers per Transpower GXP

Central Park

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 customers, the 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 loss and customers without supply. Central Park substation supplies seven zone substations with circa 50,000 customer connections and a maximum demand of approximately 150 MVA. There is very limited capacity for the shifting of load onto the Wilton GXP with approximately 17 MVA able to be transferred to Moore Street, Kaiwharawhara and Karori substations. The area supplied by Central Park contains the majority of the Wellington CBD and includes a number of high-priority and regionally critical sites.

The Central Park site, shown in Figure 12-1, is constrained by the limited available space as well as the construction standards at the time of construction which increases the likelihood of a failure in one area spreading to adjacent areas or equipment. Large Transpower sites such as Penrose or Haywards are often

300-400m across while Central Park is barely over 50m across with no fire separation between two of the transformers or between bus sections in the 33 kV switchroom.

Figure 12-1 Central Park Substation

This site supplies the majority of the CBD load in the national capital city and there is no alternate supply in the event of a failure of the site. The potential loss of the majority of Wellington city load is an unacceptable risk and there is ongoing work between WELL and Transpower looking at potential solutions to improve the resilience of the site. This is discussed further in Section 12.5.1.

Melling

Melling GXP supplies three WELL zone substations and circa 20,000 customer connections, comprising the primary commercial and residential areas of Lower Hutt, New Zealand's sixth most populous city.

Melling, shown in Figure 12-2, is located within the stop banks of the Hutt River, placing it at risk of flooding and erosion. The switchgear at the site is located in an elevated switchroom above the expected flood level, however, there is a risk of debris damaging the 110/33 kV transformers and 110 kV towers in the yard.

Transpower is assessing the flood risk for the site and expects to develop a long-term plan for the site by late 2025.

Figure 12-2 Melling Substation

The major costs for WELL associated with relocating Melling GXP relate to the oil-filled 33kV cables supplying Waterloo and Naenae. These cables are currently proposed for replacement due to asset health during DPP5. There would be additional costs associated with replacing the load control plant currently located in a WELL-owned building on the Transpower site.

In the event of a flood interrupting supply from Melling GXP, WELL would transfer the load to Haywards and Gracefield GXPs. This transfer capability has been estimated as 54% of the winter peak demand and 67% of the summer peak demand. The remaining customers will be without supply until Transpower is able to restore power to the GXP. In the event of the Transpower outage being prolonged, WELL would deploy its earthquake readiness spares (see Section 12.4.2.4) to re-establish a temporary overhead 33 kV connection from other GXPs to its affected zone substations.

Pauatahanui

Pauatahanui GXP is located north of Porirua city, supplying circa 7,000 customers via WELL's Plimmerton and Mana substations.

Pauatahanui GXP is situated within a 1-in-10-year flood zone.[54] The most recent significant flooding event at the site occurred in 2016, with 0.6m of water through the site causing damage to WELL's batteries and communications equipment at the site.

Transpower is investigating options for either upgrading or relocating Pauatahanui GXP to resolve the flood risk. WELL is assessing options for the relocation of WELL's equipment as part of this project.

[54] https://poriruacity.govt.nz/your-council/city-planning-and-reporting/district-plan/proposed-district-plan/past-consultations/porirua-flood-mapping/

The consequences of flooding at Pauatahanui are unlikely to include loss of supply to WELL's substations. In an event similar to 2016, the consequences for WELL are likely to be the loss of its SCADA connection to the site, and the battery backup for the protection intertripping to Mana and Plimmerton zone substations.

12.4.2.4 Major Earthquake

The Wellington Region contains numerous known fault lines with the potential to cause a severe shaking event. The three most well-studied fault lines in the region are the Wellington, Ohariu, and Wairarapa fault lines. These are shown in Figure 12-3, a map of the region created by GNS science.

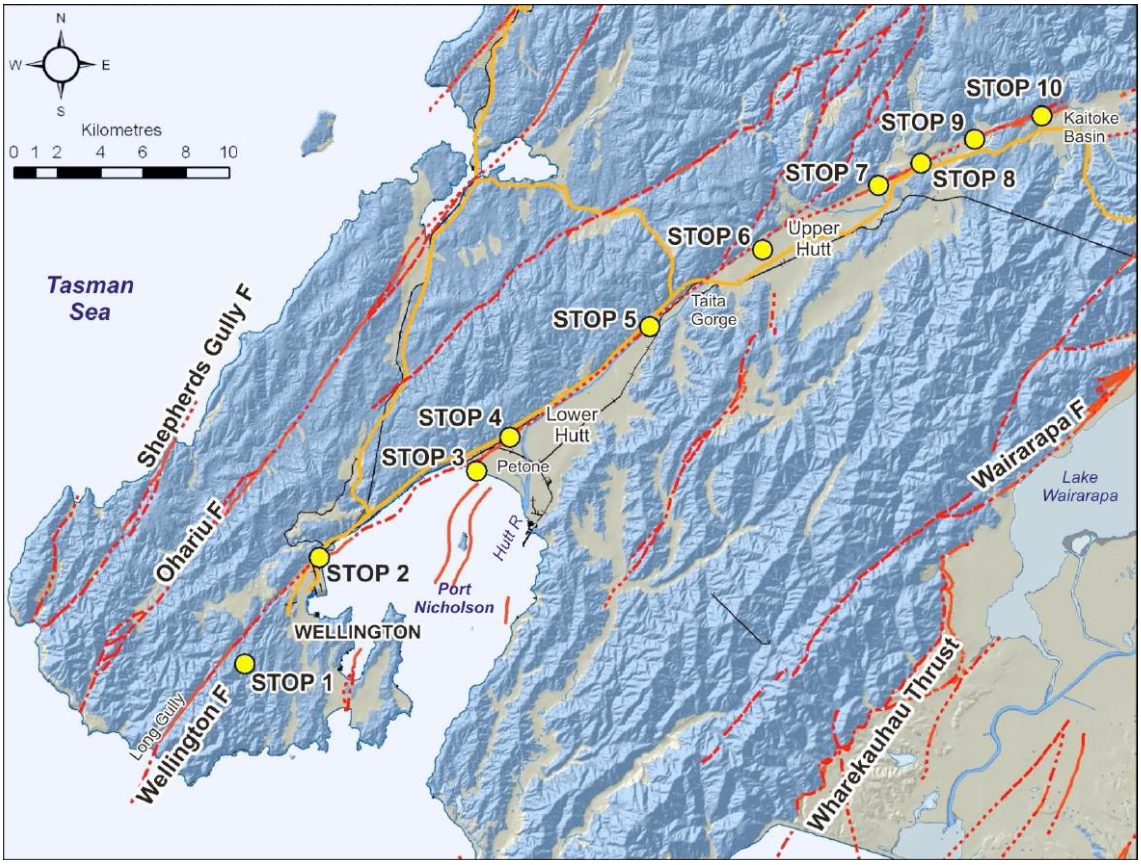

Figure 12-3 Wellington Region Fault Lines[55]

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 Remutaka 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.

In addition to these local fault lines, the Hikurangi Subduction Zone to the east of North Island has been assessed as having a 25% probability of causing a magnitude 8+ earthquake in the next 50 years.[56]

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

[55] 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).
[56] https://www.eastcoastlab.org.nz/home/article/216/

large sections of the network will be without power immediately after a major event. Damage to transport links is expected to prevent road movement between Wellington and the Hutt Valley for a period of weeks.[57]

To identify potential resilience improvements, WELL has estimated the damage that would be caused to the network by a major earthquake in the Wellington region. In normal service, when there is an outage due to equipment failure, the area that has lost supply is usually able to be supplied from an adjacent feeder or zone. These damage estimates indicate that supply from adjacent feeders would not be possible following a major earthquake. As a result, there would be extended outages in much of the network and restoration would be slowed by difficulties with transport into and within the region.

Restoration time estimates were separated into the time for transport into the area to be available and the time to repair the damage. These outage durations are consistent with previous estimates which identified that restoration could take in excess of 90 days.

The 2016 Kaikoura Earthquake reinforced that a major earthquake within the region would cause major disruption to the electricity network, and power outages that would last longer than is acceptable even in an extreme event. To enable mitigation work WELL applied for a CPP targeting improving readiness, which was approved in 2018.

The readiness CPP was split into five workstreams with each delivered as a separate project:

1. Spares - The spares workstream was split into three projects with overhead line spares, cable and joint spares, and the procurement of a mobile 11 kV switchboard. The Spares workstream also included the setup of storage locations throughout the network to reduce the impact of severed transport links, and to allow repair and restoration of the network to begin without needing to rely on resources from outside the region.

2. Data Centres - Three data centres have been 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.

3. Mobile Substations - Two mobile 33 kV/11 kV substations have been constructed to restore supply where a substation is so damaged that the transformers and/or switchboard are unable to be used. The substations have been constructed in a modular manner with the transformer and switchgear/controls units separately transportable. The transformer is mounted on a trailer with the switchgear/control module fitting the dimensions of a standard 20ft shipping container. This arrangement is due to transport considerations. With road access being potentially affected, a smaller trailer and container are more easily transported from the storage location to a damaged substation. This arrangement also provides more flexibility in connection and the physical layout on site.

4. Radio and Phones - A modern digital radio system has been installed to improve connectivity and coverage while reducing reliance on cellular networks, which are unlikely to be functional following a major event. A VoIP telephone system has been installed to provide improved connection functionality between the network control room and zone substations.

5. Seismic Reinforcement – WELL has had an ongoing programme of work to reinforce buildings constructed before 1976 that have been identified as having a strength of less than 34% of the New

[57] "Restoring Wellington's Transport Links after a Major Earthquake" WeLG/WREMO, March 2013.

Building Standard (NBS). As a part of the CPP, this programme was expanded to include the strengthening of 91 significant substations to a minimum of 67% of NBS.

A risk related to a major earthquake is the potential for a tsunami to affect Wellington. WELL's head office in Petone is located in a tsunami evacuation zone.[58] WELL has commenced planning to relocate its head office away from the coast in order to mitigate this risk. This relocation is currently expected to occur in 2025/26.

12.4.2.5 Flooding and Storm Inundation

In addition to causing widespread damage in the overhead network, major storms can result in flooding and landslides in parts of the region. While this does not cause the same widespread network damage it does have an effect on the response times as roads become blocked, making access to some areas difficult or impossible. In addition, flooding can cause lasting damage by destroying secondary systems such as protection and control equipment and accelerating the corrosion of metallic components.

Wellington Water has been undertaking flood risk modelling for the city councils. During 2024 WELL plans to overlay the results of these models with its asset criticality modelling to assess the level of risk posed to the 11kV and 400V network. This work will then lead to a set of recommended actions to proactively mitigate or reduce high risk for affected assets.

Porirua Zone Substation

Porirua Zone Substation supplies circa 7,000 customers in Porirua City, Cannons Creek, Aotea, and Titahi Bay. It has been identified that the switchroom and transformer yard at the Porirua zone substation are at risk of stormwater ponding. The substation is currently planned to be rebuilt during DPP4, and as part of that project, the replacement switchroom will be constructed in a lower-risk position on the site. Refer to Section 9.5.2.6 for more information about this project.

Plimmerton Zone Substation

Plimmerton Zone Substation supplies circa 2,400 customers north of Porirua. Landslides have occurred on the hill behind the substation during periods of heavy rain. The substation is planned to be relocated during DPP4 as part of its redevelopment to support load growth in the Plimmerton Farm development.59 Refer to Section 9.5.2.5 for more information about this project.

Riverlink

Riverlink is a Greater Wellington Regional Council-led project to strengthen Lower Hutt's defences against flooding from the Hutt River.[60] WELL has a number of important assets that will be protected by the new stop banks. The cost of each individual asset owner protecting themselves against flooding would be significantly greater than the cost being expended by the Regional Council, and the mitigation provided will be more secure. This is one of the lessons that has been learned from Cyclone Gabrielle, where stop banks were overtopped, leading to failures of the infrastructure that they were protecting.

[58] https://www.huttcity.govt.nz/services/emergency-management/useful-information/maps
[59] https://poriruacity.govt.nz/your-council/city-planning-and-reporting/district-plan/responding-to-growth/plimmerton-farm-overview/
[60] https://teawakairangi.co.nz/

12.4.2.6 Wildfire

The Wellington region has not traditionally been susceptible to wildfire. However, it has been identified through engagement with the Greater Wellington Regional Council that there are several areas where the risk of wildfire is significant, and the size and number of these areas are likely to grow due to climate change.

WELL has engaged with its Australian sister companies to understand the strategies that they employ to minimise bushfire risk. WELL will use this information to develop its own wildfire mitigation policy. This policy will include enhanced design standards for wildfire-prone areas, protection and control strategies (such as auto-reclose blocks during periods of elevated risk) and communication protocols with relevant agencies.

12.4.3 Summary of Primary Resilience Risks

Table 12-2 summarises WELL's primary network resilience risks, and the actions underway to address them.

Risk	Risk Type	Action
Major Earthquake	Seismic	Readiness CPP completed in 2021, including procurement of spares and substation strengthening (Section 12.4.2.5). Replacement of gas-filled 33 kV cables by 2032 (Section 12.5.2).
Tsunami	Flooding	Relocation of WELL head office by 2026 (Section 11.6).
Central Park GXP	Fire	Transpower project to extend the site by 2026 (Section 12.5.1).
Melling GXP	Flooding	Transpower to develop a long-term plan by 2025.
Pauatahanui GXP	Flooding	Transpower to investigate options.
Porirua Zone Substation	Flooding	Substation rebuild planned for 2025 (Section 9.5.2.6).
Plimmerton Zone Substation	Landslide	Substation relocation planned for 2027 (Section 9.5.2.5).
Flood or Storm Surge Event	Flooding	Undertake distribution network flood risk assessment during 2024. Engagement with Greater Wellington's ongoing Riverlink project. Trialling submersible low voltage pillars on Wellington's south coast.
Wildfire	Fire	Engagement with Greater Wellington to identify high fire risk areas. Engagement with Australian sister companies to understand their bushfire risk reduction strategies. Wildfire Risk Reduction Policy to be developed and implemented in 2024.

Table 12-2 Summary of Primary Resilience Risks

12.5 Wellington Lifelines Regional Resilience Project

The Wellington Lifelines Regional Resilience Project (WeLG RRP) was initiated by WeLG in the aftermath of the 2016 Kaikoura Earthquake, to assess the resilience of lifeline services and to compile a coordinated business case for resilience expenditure. The project published its report in October 2019, which can be found at https://wremo.nz/about-wremo/wremo-library/reports/.

The economic modelling indicated that a single 7.5-magnitude event on the Wellington fault line could adversely impact the national GDP by $16.7 billion over a five-year period. Hazard and damage state modelling was done through RiskScape, a multi-hazard risk assessment tool developed by GNS and NIWA.

Lifeline industries were engaged to assist with fragility curves and damage restoration time frames. Economic impact was assessed using MERIT (Modelling the Economics of Resilient Infrastructure Tool) which assesses not only the immediate damage but longer-term economic impacts as well.

A range of options of varying expenditure were identified and passed through the same modelling process to identify the overall benefit, recommending an investment of $3.9 billion which could reduce the GDP impact of a major earthquake by $6.16 billion.

The preferred option included a $205 million investment in the regional electricity infrastructure, as shown in Table 12-3.

Initiative	Owner	Indicative Cost (2019)	Status
Central Park Substation improved resilience	Transpower, WELL	$40m	In Progress (Section 12.5.1)
Seismic upgrade of cables and creation of 33kV rings	WELL	$160m	In Progress (Section 12.5.2)
Central Park to Frederick Street Cable Replacement	WELL	$5m	Complete

Table 12-3 Electricity Expenditure for Preferred Regional Resilience Investment Option
Source: Wellington Lifelines Project Report, 2019

The preferred option involved three initiatives to improve the resilience of the electrical networks in the Wellington region. The most vulnerable assets in the region are the fluid and gas-filled subtransmission cables, which could be mitigated by cable replacement in a more resilient ring configuration. Another major risk is the single point of failure at Central Park Substation, with this substation being the main supply point for most of Wellington City. The third initiative is the replacement of the Central Park to Frederick Street cable, which was separated from the main seismic upgrade of cables because the cable was already planned for replacement for capacity reasons.

The WeLG RRP initiatives were not included within the 2018 CPP discussed in Section 12.4.2.4 as this was focused on the quick implementation of readiness initiatives. As such these longer term works were outside the scope of the CPP, and the level of investment required is beyond what can be funded within the DPP allowances. While the items implemented as part of the readiness programme will provide an improvement to restoration times, there may still be significant outages in many areas of the network depending on the scale of any earthquake occurring, hence the potential need for this extra work.

12.5.1 Central Park

There is a significant risk posed by a potential loss of supply at Central Park GXP, and WELL and Transpower have been investigating options to improve their supply resilience. The most effective means of reducing this risk is the construction of a smaller “Central Park II” substation which will replicate a portion of the existing site at a nearby location. The Central Park II substation construction will coincide with the decommissioning of one transformer bank at the current 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 will be operated as a physically separated extension of the existing GXP. Transpower’s schedule for the delivery of the project is shown in Table 12-4.

Project Activity	Timeframe
Land acquisition and consenting	Q1 2024 to Q3 2024
Detailed investigation	Q2 2024 to W3 2024
Detailed Design	Q4 2024 to Q2 2025
Construction	Q3 2025 to Q1 2027

Table 12-4 Timeframe for Construction of Central Park II

The substation work will be funded under a new customer connection contract with Transpower and recovered as a pass-through cost to end customers. The connection of the new substation into WELL's network will need to be funded under DPP4, however the cost of this is not yet able to be estimated. It is expected that the project will be funded as a Foreseeable Large Project.

12.5.2 Subtransmission Fluid-Filled Cables

The majority of the subtransmission cables in the WELL network are fluid-pressurised cables, installed between 1960 and 1980. Fluid-filled cables are particularly prone to damage in an earthquake as well as being expensive and time-consuming to repair, requiring skills that are not readily available within the region.

The condition of these cables is individually monitored and assessed against asset health and criticality criteria. These cables have historically given a high level of reliability and are manageable from an operational point of view for the planning period as described in Section 8.5.1.

A significant earthquake could result in cable damage that does not immediately cause a fault, such as fluid leaks or sheath damage, but which would have a negative impact on the reliability of the network. Repairing a fluid leak is a difficult task as the means of locating the leak can take time when there is no associated cable fault, resulting in leaks having a high cost to locate and repair, as well as ongoing costs while fluid is being lost. Once the damage is located, repair work can also be time-consuming and requires a specialised skill set to be brought in from outside the region. Due to these repair difficulties and the high likelihood of a fault causing damage in an earthquake, repair of these cables may not be a viable solution. The CPP spares project provided 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 Regional Resilience Project analysed the effect of subtransmission upgrades on the potential restoration times, based on damage modelling work carried out by GNS Science. The construction of rings was grouped into three separate projects for the purpose of this analysis:

- A subtransmission ring through the eastern suburbs of Wellington;
- A subtransmission ring in Lower Hutt; and

- The seismic upgrade of other fluid-filled cables.

The damage modelling has identified the construction of two subtransmission rings as the preferred option for improving the resilience of electricity distribution in the Wellington region.

The replacement of gas cables will be completed as 33 kV circuits are replaced due to condition or capacity. The need to upgrade subtransmission cables due to the impact of the Emissions Reduction Plan has accelerated this work, resulting in an integrated cable replacement programme that will significantly improve the resilience of the Wellington electricity network over the next eight years. The gas-filled subtransmission cables are planned for replacement as outlined in Table 12-5.

Subtransmission Circuits	Cable Type	Project Completion Timeframe	Change due to ERP	Project Driver
University	Gas	2026	No change	Condition
Evans Bay	Gas	2027	-5 years	Capacity
Hataitai	Gas	2027	-8 years	Capacity
Ira Street	Gas	2028	-5 years	Capacity
Karori	Gas	2029	No change	Condition
Waikowhai	Gas	2031	-6 years	Capacity
Maidstone	Gas	2032	No change	Condition

Table 12-5 Timeframe for Gas-Filled Cable Replacement

Subtransmission rings will allow for greater load transfer between zone substation and GXPs and the associated cable replacement would enable diversification of cable routes. The new 33 kV bus at Evans Bay discussed in Section 9.4.2.2 is the first step in creating the subtransmission rings for Wellington’s eastern suburbs.

Section 13
Customer Initiated Projects and Relocation

13 Customer Initiated Projects and Relocations

This section provides information on customer-initiated projects and relocations on WELL's network over the next 10 years. New connections or the changing of existing connections initiated by customer projects have an impact on WELL's long-term network planning and development strategy. The introduction of new technologies (e.g. energy storage systems, demand response programmes etc) will also affect WELL's ability to maintain supply quality and network capacity.

Expenditure for customer-initiated projects and relocations has been aggregated in the budget in accordance with the categories discussed below.

13.1 New and Altered Connection Application Process

Applications for new and altered connections are made through WELL's website, allowing customers to register their request for a new connection.[61] These are broadly categorised into either residential or business connections, with fuse sizing requirements of 60A, 100A, or greater than 100A rating requests.

The approach to communication with customers is determined by the complexity of the work. The customer's retailer is WELL's point of contact for a standard residential new connection. The service levels for communication with retailers about new connections are defined in the Code and the DDA, and are provided in Section 6.5.4. Projects that require network extensions are managed directly with the customer's representative by WELL's Service Delivery team. Communication for the livening process is undertaken directly between WELL's Field Service Provider and the customer's electrician.

A key element of communication with customers is setting clear expectations of timeframes, and the customer's responsibilities, early in the new connection process. The current lead time for new connections requiring a new point of supply is displayed on the new connections request portal on WELL's website.

Delays can occur on both the network and customer side of the new connection process. Network-related delays can be caused by contractor availability, the variability of work volumes, and the lead times for any major materials that may be required, such as transformers. Delays can also be caused by incomplete information being provided to WELL, the installation not being ready to be connected on the agreed date, and essential documents such as the installation's certificate of compliance not being complete.

WELL seeks to continuously improve its new connections processes. A recent innovation has been the introduction of a flat-fees structure for the majority of residential connections to make the process quicker and simpler for customers. Simple new connections (typically residential customers) can usually be completed within three months using standard designs and pricing. In addition, WELL regularly surveys customers and electricians to monitor the performance of the process and look for further ways it could be improved.

13.1.1 Complex New Connections

Where new or altered connection applications are identified as complex, the Service Delivery team evaluates the customer's requirements, collects information for these applications, constructs a brief project scope with material requirements, and compiles a Technical Approval (TA) form for submission to the Engineering Planning team.

[61] https://www.welectricity.co.nz/getting-connected/new-online-forms-holder/get-connected/

Upon receipt of this TA request, the Engineering Planning team reviews and further defines the project as either minor or major, and completes the approval process accordingly. For complex–minor projects, basic checks include system capacity analysis, contingency analysis, an equipment type review, and a secondary asset requirements review. After completing these assessments, the TA is returned to Service Delivery for tendering. Once the competitive tender process is complete, a tender evaluation is undertaken which will determine pricing for a quotation. This is then structured into a formal offer and presented to the customer.

Applications classified as complex–major require more in-depth analysis. Applications such as these may trigger a High-Level Response (HLR) query. A study is conducted illustrating the load flow analysis and network constraints. Several viable options for delivering the required supply capacity are detailed including project durations and cost estimates. This HLR is presented to the customer to enable them to select an option that best matches their requirements.

A Detailed Solution Development (DSD) study may be initiated to further refine the project requirements and estimates. This is completed by an independent consultant. One of the primary objectives of this exercise is to validate the selected option and refine the estimate.

Upon completion of the DSD process, the customer may opt to pursue the selected option. Where the level of complexity of the planned installation is high, then an independent design consultant may be engaged for the detailed design. The detailed design is integral for the construction tender process to enable pricing from the installation contractors. On completion of the tender evaluation and internal approval processes, Service Delivery will make a formal connection offer to the customer based on the requirements specified in the development process.

Throughout this process for complex new connections, WELL seeks to minimise the cost to customers through the use of standardised designs and materials, competitive tendering to multiple contractors, and a customer contributions policy that seeks to ensure fairness between existing, new, and future customers. WELL’s customer contributions policy is discussed further in Section 13.8.

13.2 New Connections and ICPs

The number of new dwellings consented annually in the Wellington Region across the four local authorities covered by WELL’s network peaked in 2022, with 2023 showing a significant reduction. Figure 13-1 shows the number of new dwellings consented over the last six seven years.

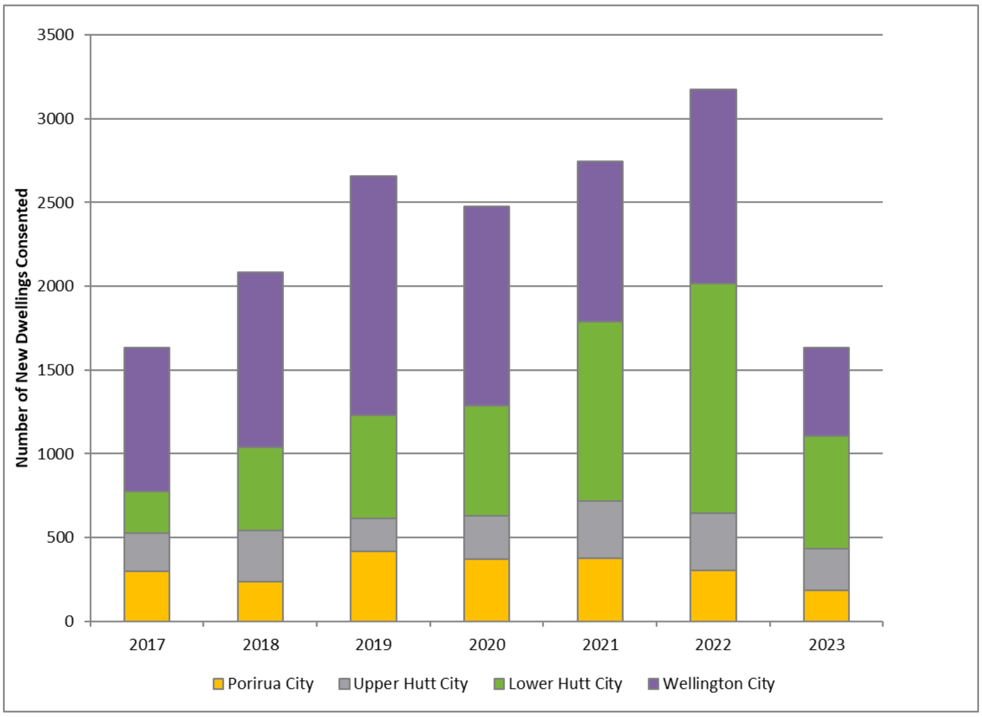

Figure 13-1 Number of New Dwellings Consented in the Wellington Region[62]

Figure 13-2 shows the trend in the types of dwellings being consented in the Wellington Region. There has been a clear trend towards the development of multi-unit dwellings, including apartments, retirement villages, and townhouses. This shows that recent residential growth in Wellington has primarily been driven by housing intensification. The impact of this trend on WELL's network is discussed in Section 9.

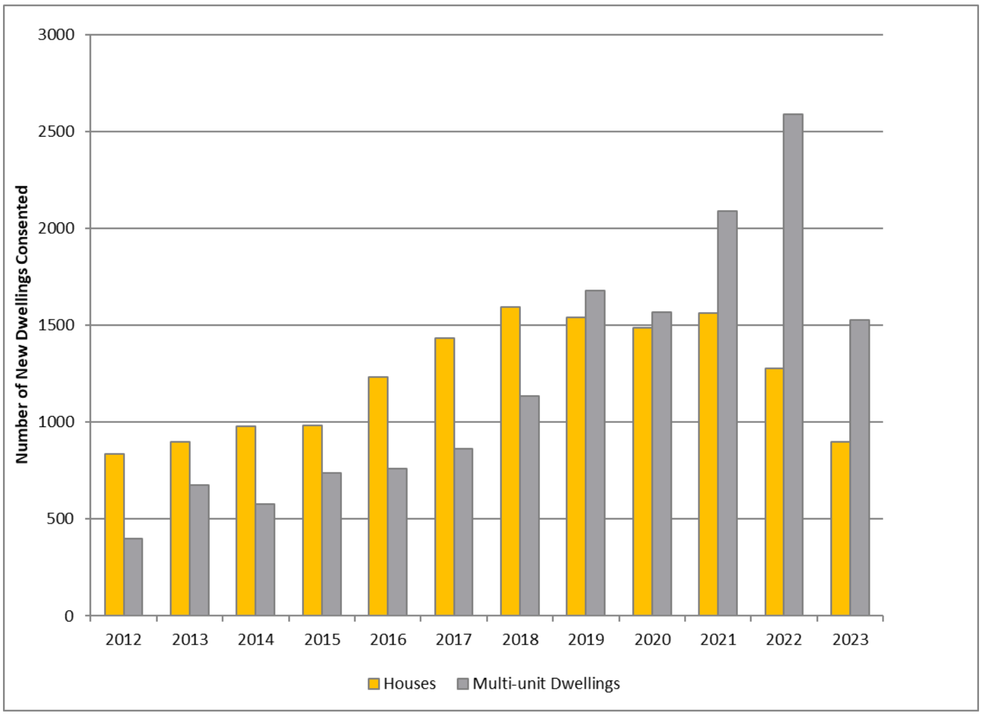

Figure 13-2 Types of New Dwellings Consented in the Wellington Region[63]

[62] https://www.stats.govt.nz/information-releases/building-consents-issued-december-2023/

[63] https://www.stats.govt.nz/information-releases/building-consents-issued-december-2023/

Figure 13-3 shows the number of new connections added to the Wellington network since 2019 and the expected new connections for the next five years. The number of new ICP connections does not align with building consents due to the lag between consent approval and connecting to the network (which can be between one and five years) and because some dwellings containing multiple units are serviced by a single ICP connection.

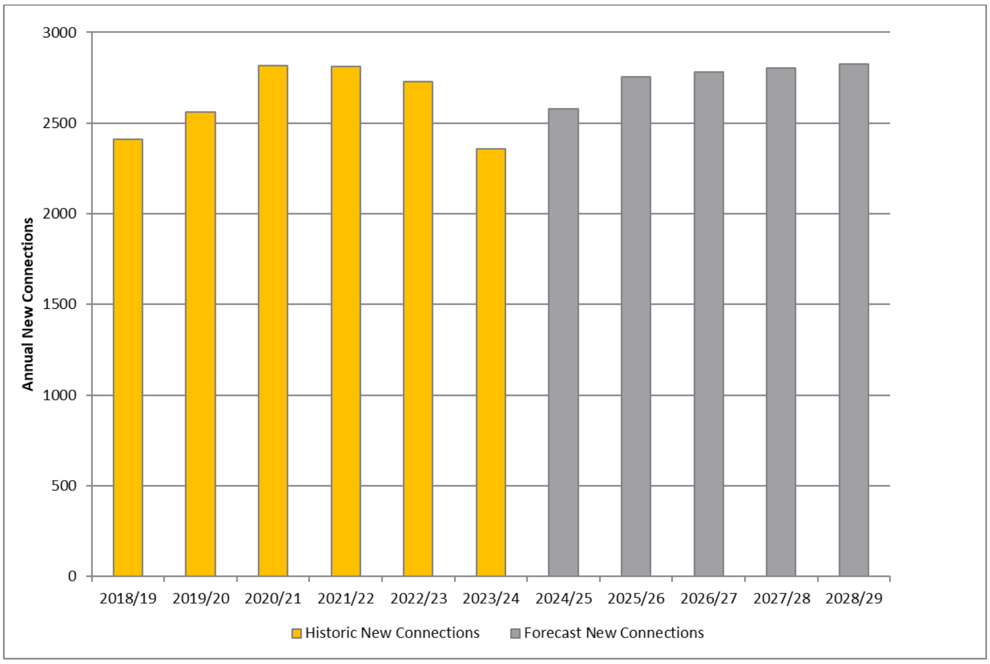

Figure 13-3 New Connections in the Wellington Region

WELL expects the current levels of new connections to continue, growing at around 2,800 new connections per year. This is based on WELL's forward work programme indicating that the development of previously consented subdivisions is continuing. This is in line with the long-term population growth demand forecast provided in Section 4 (reflecting approximately 20% of future demand growth).

13.3 Substations

Substation projects include new transformers and HV connections, often required to meet the capacity requirements of new businesses. The requests for large substation connections have been consistent for several years. The forecast is set conservatively to reflect the uncertainty about whether individual projects will go ahead, however, a number of large customer projects requiring additional capacity are proposed which could significantly increase expenditure if the customers decide to proceed in 2024.

13.3.1 Industrial and Commercial Gas Conversions

Included in the substation connection forecast is a forecast for commercial and industrial gas-to-electricity conversions. As outlined in Section 4, the ERP requires homes and businesses to transition away from using fossil gas. DETA is developing a transition plan on behalf of EDBs, EECA, and Transpower. DETA has finished its survey of Wellington, which indicates there could be up to 40 MW of new electricity capacity needed across 34 entities. An initial forecast has been included in the Substation Connection CAPEX that assumes 34 connections averaging 1 MVA each across the next 10 years, with the conversions needing to be completed by the end of the decade to meet the government's emissions reduction targets.

There are gas users that did not respond to the survey which may also convert to electricity in the future. WELL will refine this forecast as more information is gathered for each conversion. It may be that larger connections will also need network reinforcement which will increase the forecasts.

13.4 Subdivisions

Small and infill subdivisions have been increasing over recent years. Developers continue a trend where the appetite for large-scale residential (>100 lots) subdivisions is still increasing, particularly in the northern areas of Wellington and Porirua cities. Additionally, industrial-type subdivision requests have been received to cater for smaller commercial and manufacturing businesses.

13.5 Capacity Changes

Expenditure associated with transformer upgrades or downgrades is included within the customer substation area of the customer connection forecasts.

13.6 Relocations

Relocation projects are primarily initiated by Waka Kotahi or local authorities, but can also be private customer-initiated relocations. State Highways and local authority road safety improvements are critical projects in this category.

WELL is engaging with the Greater Wellington Regional Council-led Riverlink project.[64] This project will strengthen Lower Hutt's defences against flooding from the Hutt River, and construct a new bridge and interchange on State Highway 2 at Melling. The project is expected to require the relocation of 33 kV cables, 11 kV cables, and distribution substations. WELL expects to make a reopener application for this project once the scope and timing of the required relocations has been confirmed.

WELL has made a reopener application for an additional relocation allowance to relocate its primary data centre, backup control room, and disaster recovery services from Haywards to a new building in Tawa, following the termination of WELL's lease of the Haywards site by Transpower. This is a complex move as it affects SCADA, WELL's primary data centre, and communications equipment, as well as connected party asset relocations within the GXP. This project is underway and will be completed in 2024.

13.7 Reopeners for Large New Connections

The DPP regulatory framework allows network operators to apply for additional allowances for unforeseen new connections, network reinforcement, or relocations that were not included in the regulatory allowance calculation set every five years. The Commission added this new feature to the regulatory allowance calculation, in recognition of the changes in the electricity sector which are driving increased uncertainty in the level of electricity demand, new connections, and the way distribution networks will need to be managed.

In the 2023 AMP, it was indicated that WELL was expecting to make reopener applications for public transport electrification. However, the customers have advised that these projects have been delayed until the next regulatory period, and it is therefore no longer necessary to apply for a reopener in DPP3 to fund these projects.

[64] https://teawakairangi.co.nz/

WELL has made a reopener application for one large customer connection project. This project has been included in the relevant capex budget categories of this AMP.

13.8 Large Customer Connections

Recent Input Methodology changes include a new Large Customer Connection mechanism which allows large connections (greater than 5 MW) to be negotiated outside of the regulatory framework. Table 13-1 lists projects that are currently included in the System Growth and Reinforcement expenditure forecast, which could be eligible for the Large Customer Connection mechanism.

Regulatory year	2025/26	2026/27	2027/28	2028/29	2029/30	Total
KiwiRail network capacity upgrade	-	14,333	11,083	-	-	25,416
Bus charging hub	6,750	-	-	-	-	6,750
Total	**6,750**	**14,333**	**11,083**	**-**	**-**	**32,166**

Table 13-1 Possible Large Customer Connection Projects (\$K in constant prices)

13.9 Capital Contributions

The cost of connecting to the network or altering existing services is the capital cost of designing and installing the new connection assets or any new assets needed to adjust a customer's existing services. These costs are for assets that only the connecting customer benefits from and are funded by a combination of tariff and upfront customer capital contribution.

A customer capital contribution payment is a one-off payment made at the start of a project and is used to directly fund capital works. The Input Methodologies used to calculate the ongoing allowances an EDB has to fund the operation of its network require that customer capital contributions are excluded from the allowance calculation. This reflects that the customer rather than WELL has funded some or all of the capital costs of connecting. This also means that the customer capital contribution is excluded from tariffs, ensuring the assets are not paid for twice.

Customer capital contributions are excluded from allowances by subtracting the contributions from the value of the assets added to the Regulatory Asset Based (RAB). The RAB records the value of the assets that the EDB has invested in and is used to calculate the allowances that a distribution network operator is provided to recover the cost of purchasing the assets and the return for making that investment. Excluding customer capital contributions from the RAB ensures a customer's investment is not included in the revenue used to set tariffs, i.e. ensuring that the costs of the assets funded directly by customers are not included in the overall target revenue and therefore that those costs are excluded from tariffs.

WELL calculates customer capital contributions as the incremental cost of the new connection or change to the existing connection plus a contribution towards the shared network costs, less the incremental revenue provided by a new connection or a change to an existing connection.

Customer Capital Contribution = Incremental Cost of Connecting + Contribution towards Shared Network Costs − Incremental Revenue from Connection

Figure 13-4 Customer Capital Contribution Calculation

safer together

This ensures that the connecting customer receiving the benefits from the connection funds all of the costs of connecting or augmenting the existing connection over the life of the assets that benefit solely them. This ensures that existing customers are no worse off.

13.10 Customer Connections Summary for 2024-2034

The total forecast customer connection capital expenditure for 2023 to 2033 is presented in Table 13-2.

Customer Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Substation	6,815	9,326	9,326	9,326	9,326	7,301	7,301	7,301	7,301	7,301
Subdivision	4,487	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103
High Voltage Connection	2,511	2,856	2,856	2,856	2,856	2,856	2,856	2,856	2,856	2,856
Residential Customers	309	351	351	351	351	351	351	351	351	351
Public Lighting	28	32	32	32	32	32	32	32	32	32
Total Gross	**14,150**	**17,668**	**17,668**	**17,668**	**17,668**	**15,643**	**15,643**	**15,643**	**15,643**	**15,643**
Less Customer Capital Contributions	-9,905	-12,368	-12,368	-12,368	-12,368	-10,950	-10,950	-10,950	-10,950	-10,950
Total Net of Contributions	**4,245**	**5,300**	**5,300**	**5,300**	**5,300**	**4,693**	**4,693**	**4,69**	**4,693**	**4,693**

Table 13-2 Customer Connection Capital Expenditure Forecast ($K in constant prices)

13.11 Asset Relocations Summary for 2024-2034

The forecast asset relocation capital expenditure, which is primarily related to either roading projects or the undergrounding of the existing overhead network for subdivision development, is presented in Table 13-3.

Programme	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Asset Relocations	758	773	788	804	820	837	853	870	887	887
DR Site Reopener	700	-	-	-	-	-	-	-	-	-
Total Gross	**1,458**	**773**	**788**	**804**	**820**	**837**	**853**	**870**	**887**	**887**
Less Customer Capital Contributions	-531	-541	-552	-563	-574	-586	-597	-609	-621	-621
Total Net of Contributions	**927**	**232**	**236**	**241**	**246**	**251**	**256**	**261**	**266**	**266**

Table 13-3 Asset Relocation Capital Expenditure Forecast ($K in constant prices)

Section 14

Expenditure Summary

14 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.

14.1 Capital Expenditure 2024-2034

14.1.1 Customer Connections

The total forecast customer connection capital expenditure for 2024 to 2034, as discussed in Section 13, is presented in Table 14-1.

Customer Type	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Substation	6,815	9,326	9,326	9,326	9,326	7,301	7,301	7,301	7,301	7,301
Subdivision	4,487	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103	5,103
High Voltage Connection	2,511	2,856	2,856	2,856	2,856	2,856	2,856	2,856	2,856	2,856
Residential Customers	309	351	351	351	351	351	351	351	351	351
Public Lighting	28	32	32	32	32	32	32	32	32	32
Total	**14,150**	**17,668**	**17,668**	**17,668**	**17,668**	**15,643**	**15,643**	**15,643**	**15,643**	**15,643**

Table 14-1 Customer Connection Capital Expenditure Forecast
($K in constant prices)

14.1.2 System Growth

The total forecast capital expenditure for system growth and security of supply for 2024 to 2034, is presented in Table 14-2.

Asset Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Subtransmission	439	-	42,890	15,000	-	15,000	-	14,000	-	-
Zone Substations	-	6,000	107,691	90,000	54,000	-	50,870	-	-	-
Distribution Poles and Lines	-	200	200	200	200	600	100	100	100	100
Distribution Cables	2,280	45,398	22,288	41,088	90,378	100,753	5,101	23,264	7,122	5,792
Distribution Substations	-	12,600	12,600	12,600	12,600	10,100	10,100	10,100	10,100	10,100
Distribution Switchgear	-	-	-	-	-	-	-	-	-	-
Other Network Assets	-	-	-	500	-	-	-	-	-	-
Total	**2,719**	**64,198**	**185,669**	**159,388**	**157,178**	**126,453**	**66,171**	**47,464**	**17,322**	**15,992**

Table 14-2 System Growth Capital Expenditure Forecast
($K in constant prices)

14.1.3 Asset Replacement and Renewal

The total forecast capital expenditure for asset replacement and renewal for 2024 to 2034 as discussed in Section 8 is presented in Table 14-3. This includes provision for replacements that arise from condition assessment programmes during the year.

Asset Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Subtransmission	1,512	12,500	-	8,500	10,000	-	10,000	10,000	10,500	-
Zone Substations	2,460	470	470	470	470	470	470	470	470	5,470
Distribution Poles and Lines	7,142	7,250	7,268	7,145	7,075	6,900	6,813	6,428	6,445	6,323
Distribution Cables	2,705	2,734	2,734	3,206	3,206	3,206	3,206	3,206	3,206	3,206
Distribution Substations	5,486	5,317	5,317	5,537	5,262	5,070	5,070	5,345	5,429	5,869
Distribution Switchgear	6,161	9,518	9,982	6,777	6,537	6,534	6,569	6,570	6,614	6,469
Other Network Assets	4,500	4,562	3,974	4,572	3,850	3,850	3,850	3,850	3,850	3,850
Total	**29,966**	**42,351**	**29,745**	**36,207**	**36,400**	**26,030**	**35,978**	**35,869**	**36,514**	**31,187**

Table 14-3 System Asset Replacement and Renewal Capital Expenditure Forecast
($K in constant prices)

14.1.4 Asset Relocations

The forecast asset relocation capital expenditure, primarily related to roading projects, is presented in Table 14-4.

Programme	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Roading Relocations	758	773	788	804	820	837	853	870	887	887
DR Relocation	700	-	-	-	-	-	-	-	-	-
Total	**1,458**	**773**	**788**	**804**	**820**	**837**	**853**	**870**	**887**	**887**

Table 14-4 Asset Relocation Capital Expenditure Forecast
($K in constant prices)

14.1.5 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 14-5.

Programme	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Feeder Reliability Projects – Lines	875	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Feeder Reliability Projects – Switchgear	1,550	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Switchgear SCADA Control Retrofit	-	200	200	200	200	200	200	200	200	200
Total Quality of Supply	**2,425**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**	**2,500**
AUFLS Relay Replacement	-	4,458	-	-	-	-	-	-	-	-
Total Legislative and Regulatory	**-**	**4,458**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Resilience Expenditure	725	2,460	650	-	-	-	-	-	-	-
Total Other Reliability, Safety and Environment	**725**	**2,460**	**650**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table 14-5 Reliability, Safety and Environmental Capital Expenditure
($K in constant prices)

14.1.6 Non-network Assets

The forecast capital expenditure for non-network assets is presented in Table 14-6.

Routine Expenditure	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Software and Licenses	1,858	2,348	565	1,360	515	610	1,065	660	465	610
IT Infrastructure	614	2,245	515	1,265	785	485	1785	485	485	525
Future Services	-	2,400	600	600	600	600	200	200	200	200
Head Office Relocation	-	30,000	-	-	-	-	-	-	-	-
Capitalised Leases	2,000	-	-	-	-	-	-	-	-	-
Total Non-network Assets	**4,472**	**36,993**	**1,680**	**3,225**	**1,900**	**1,695**	**3,050**	**1,345**	**1,150**	**1,335**

Table 14-6 Non-Network Asset Capital Expenditure Forecast
($K in constant prices)

14.1.7 Capital Expenditure Summary

The total combined capital expenditure on assets is presented in Table 14-7.

Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Customer Connection	14,150	17,668	17,668	17,668	17,668	15,643	15,643	15,643	15,643	15,643
System Growth	2,719	93,198	165,370	169,688	138,178	126,453	66,171	47,464	17,322	15,992
Asset Replacement & Renewal	29,966	42,351	29,745	36,207	36,400	26,030	35,978	35,869	36,514	31,187
Asset Relocations	1,458	773	788	804	820	837	853	870	887	887
Quality of Supply	2,425	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Legislative and Regulatory	-	4,458	-	-	-	-	-	-	-	-
Other Reliability, Safety & Environment	725	2,460	650	-	-	-	-	-	-	-
Subtotal – Network Capital Expenditure	**58,743**	**163,407**	**216,720**	**226,867**	**195,565**	**171,463**	**121,146**	**102,346**	**72,866**	**66,209**
Non-Network Assets	4,472	36,993	1,680	3,225	1,900	1,695	3,050	1,345	1,150	1,335
Total – Capital Expenditure on Assets	**63,215**	**200,400**	**218,400**	**230,092**	**197,465**	**173,158**	**124,196**	**103,691**	**74,016**	**67,544**

Table 14-7 Capital Expenditure Forecast
($K in constant prices)

14.2 Operational Expenditure 2024-2034

The total forecast operational expenditure for 2024 to 2034 is shown in Table 14-8.

Category	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Service interruptions & emergencies maintenance	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289
Vegetation management	2,263	2,451	2,451	2,451	2,451	2,451	2,451	2,451	2,451	2,451
Routine & corrective maintenance and inspection	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946
Asset replacement & renewal maintenance	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
Subtotal – Network Operational Expenditure	**19,967**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**	**20,155**
System Operations and Network Support	10,169	12,336	12,760	13,077	13,080	13,262	13,262	13,262	13,262	13,262
Business Support	12,723	15,434	15,964	16,361	16,365	16,592	17,235	17,942	18,720	19,575
Subtotal – Non-network Operational Expenditure	**22,893**	**27,770**	**28,724**	**29,438**	**29,445**	**29,855**	**30,497**	**31,204**	**31,982**	**32,837**
Total – Operational Expenditure	**42,859**	**47,926**	**48,879**	**49,593**	**49,600**	**50,010**	**50,652**	**51,359**	**52,137**	**52,992**

Table 14-8 Operational Expenditure Forecast (\$K in constant prices)

Appendices

Appendix A Assumptions

Area	Assumption	Reason for Assumption	Possible Impact and Variation to Plan
Demand and Consumption	It is assumed that growth in peak demand (MW) and volume (GWh) will accelerate through the period due to decarbonisation policies leading to increased use of electricity in place of fossil fuels.	The publication of the Emissions Reduction Plan provides a pathway for New Zealand to meet its Zero Carbon 2050 obligations and places significant reliance on the transition away from fossil fuels to electricity. The increased prevalence of electric vehicle charging and the potential transition away from natural gas for residential heating will inevitably increase the demand and volume supplied by WELL's network.	Growth in maximum demand at higher levels than forecast may bring forward network reinforcement investment. Demand growth has asymmetric risk. The risk to customers of building capacity early is small compared to the risk to customers' quality of supply and ability to connect if that capacity is built too late. The lead time for developing major projects and the asymmetry of timing risk requires WELL to take an approach that assumes demand will grow and plan its system reinforcement accordingly.
Government Policy - Decarbonisation	It is assumed that the current Emissions Reduction Plan will remain in place for the duration of this Plan.	Both major political parties are committed to net zero carbon by 2050.	A change of government policy (for example a short-term prioritisation of affordability over decarbonisation) may alter the speed of decarbonisation investment, with consequential impacts on the timing of network reinforcement needs and meeting the 2050 target.
Gas Transition	WELL supports the continued use of gas as a transition fuel. This Plan assumes that New Zealand will transition from natural gas as a residential fuel to electricity by 2050, with the majority of this transition occurring outside the Planning Period covered by this Plan.	Other fuel transitions (for example relating to the residential use of coal) have occurred over periods greater than 10 years. Early indications are that hydrogen will be more expensive to produce than using electricity, existing gas appliances are unlikely to be usable at hydrogen concentrations greater than 20%, and the limited supply of biomethane is likely to be prioritised towards harder-to-electrify industrial loads ahead of residential demand.	The government's Gas Transition Plan may result in this transition happening sooner than expected, resulting in demand growing faster than forecast. Increasing gas prices due to accelerated depreciation for gas networks may drive customers to exit gas irrespective of government policy.

Area	Assumption	Reason for Assumption	Possible Impact and Variation to Plan
Inflation	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 are detailed in Schedule 14a.	Capex and Opex inflation is based on the New Zealand Reserve Bank February 2024 Monetary Forecast. CPI is used as a general forecast inflation rate, recognising current inflation volatility and that selecting different inflation measures is unlikely to add any accuracy.	The focus of the capex and opex forecast is on ensuring base costs capture recent high inflation rates. WELL recognises that the regulatory model provides a natural hedge against forecast errors and that the forecasts is used to signal the size of future cost increases, rather than being used to set nominal project budgets. Section 4.3.3 of this plan discussed the impact of increasing costs.
Operational Expenditure	WELL's operational expenditure will increase relative to historical levels.	The primary drivers of this increase in operational expenditure are: • the costs of creating a larger business to support the increased work programme required by decarbonisation targets; • Systems and data for managing the LV network; • insurance costs increasing further as a result of the increasing frequency and severity of climate change-driven weather events across New Zealand. Section 10.4 provides more detail on assumptions and drivers for OPEX.	The regulatory framework may not provide the OPEX allowances forecast to support WELL's CAPEX programme. WELL will cut its expenditure to fit the regulatory allowances and will reprioritise its CAPEX plan to reflect the size of its support functions funded by OPEX allowances. Specific costs may escalate faster than the forecast inflation rates. WELL will reprioritise its work programmes to reflect any differences in actual costs and regulatory allowances.

Area	Assumption	Reason for Assumption	Possible Impact and Variation to Plan
Unplanned Outage Quality Standard	It is assumed that the methodology for setting future quality targets will remain consistent with the Commission's 2019 determination for 2021-2025. The increased work programme required to delivery decarbonisation load growth will result in parts of the subtransmission network being placed on reduced security during construction. It is assumed that this will not lead to a significant SAIDI and SAIFI due to the processes and preparation that WELL will put in place to reduce the risk posed by these periods.	The targets adopted in this plan align with the Commission's 2019 determination for 2020-2025. This reflects WELL's intention to maintain network reliability at current levels.	Any change in quality targets, additional measures for LV quality of supply, or alteration in the assessment method, may lead to an increase in the level of investment needed to measure and maintain network performance.
Planned Outage Quality Standard	It is assumed that the Planned Outage Quality Standards imposed under Price-Quality Regulation will not unreasonably constrain the work programme required to deliver the capacity required by decarbonisation.	All planned work must be undertaken safely. While some work can occur live or without interrupting the supply to customers, in many cases this is not possible, and the supply must be interrupted in order to allow the work to safely occur.	The Commission must ensure that the Planned Outage limits are relative to the decarbonisation work programme. A Planned Outage Quality Standard that does not accommodate the volume of work needed to deliver the network capacity required to support customers' decarbonisation activities will result in delays in that capacity being built, in order to avoid a compliance breach.
Regulatory environment	It is assumed that the regulatory environment will continue to incentivise shareholders to invest in the network to ensure a sustainably profitable business. The regulatory system will be required to become more flexible in order to help EDBs deliver the services customers require.	Communication from the Commerce Commission has indicated that a fair return on investment will remain a cornerstone of the regulatory environment.	A change to the regulatory environment may lead to increased or decreased ability for shareholders to invest.

Area	Assumption	Reason for Assumption	Possible Impact and Variation to Plan
Transmission Network	Significant development of the transmission grid, and grid exit point connections, will be required in order to support decarbonisation goals. It is assumed that Transpower will manage the transmission grid and grid exit points to appropriate standards of resilience, including flood risk. It is assumed that these projects will be able to be agreed upon, funded, and delivered in accordance with the timeframe of the need.	WELL is engaging with Transpower about the transmission network needs identified in Section 9 and Section 12.4.2.3.	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.
Public Safety	Compliance with requirements for public safety management will not adversely impact the existing network assets located in the public domain. Significant asset renewals for other utilities will not lead to an increase in third party interference with works.	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.	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.
Economy – Availability and Cost of Major Equipment	It is assumed that commodity price rises and supply disruptions will stabilise at current levels. WELL will investigate long-term supply contracts to help manage lead times for critical equipment.	Local suppliers have indicated that they are adapting their business practices in response to changes in commodity and shipping availability, in order to minimise the impact on their New Zealand customers.	Worsening delays in equipment procurement could compel WELL to purchase an increased volume and range of equipment spares to be held locally by WELL, in order to minimise the impact of lead times on network and customer projects. Further cost escalations would affect the ability of WELL to deliver the programmes needed for its network within its allowances.

Area	Assumption	Reason for Assumption	Possible Impact and Variation to Plan
Technology – Demand-side Management	Demand-side management will offset some future peak demand growth. Some reinforcement expenditure will be able to be deferred through demand-side management, to increase its deliverability and reduce the price shock for customers. Demand-side management will be led by retailers and aggregators in response to price signals from the EDB.	WELL is engaged with other parties and industry bodies to help establish the technology and commercial frameworks necessary for establishing demand-side management services. WELL is learning from its sister companies overseas that have experience integrating large amounts of DER onto their networks.	Uncontrolled uptake of customers devices impacts reliability and power quality. Insufficient uptake of demand-side management would result in WELL not being able to procure the shift in demand required. Competing demands for demand-side management may result in it being used in opposition to what is needed for the safe and reliable operation of the network. If demand-side management proves to be insufficiently dependable for shifting demand or supplementing existing network capacity, then growth CAPEX may not be able to be deferred as forecast without affecting the quality of supply.
Resource Management Regulation	Changing resource management rules will not result in retrospective compliance requirements for lawfully installed existing assets.	Historic practice has been for lawfully established land use to continue being permitted under changing resource management rules.	Changes to existing network assets required by any new resource management regulation may affect WELL's ability to supply its customers. Changes to the law regarding the allocation of the cost of other utilities relocating WELL's assets as part of their own renewal programmes would force costs onto WELL that are not funded under the current regulatory regime and may affect WELL's ability to deliver its programmes.

Area	Assumption	Reason for Assumption	Possible Impact and Variation to Plan
Climate Change Adaptation – Coastal Environments	Territorial authorities will be the lead agencies making decisions about defence or managed retreat in response to storm surges, sea level rise, and coastal erosion. It is assumed that TLAs will elect to defend developed areas threatened by sea level rise.	WELL has an obligation to supply existing customers. It cannot unilaterally remove its network from potential inundation zones while there are customers that must be supplied. There has not been any indication from TLAs that any areas of WELL's network will be subject to managed retreat.	Managed retreat would require relocation or removal of WELL's assets in the affected areas. The details of each defend/retreat decision will determine whether WELL will need to adapt elements of its network in affected areas to be resistant to inundation, such as the conversion of underground networks to overhead.
High Impact, Low Probability Events	It is assumed that the delivery of this Plan will not be being disrupted by a HILP event such as a major earthquake.	Extreme disruptive events can be prepared for but cannot be predicted. WELL expects to be able to respond to routine major events such as storms and moderate earthquakes with its existing tools: its contingency planning, mutual aid agreements, strategic spares, and the readiness investments it has undertaken. The Input Methodologies allow for the recovery of expenditure to recover immediate response costs and to apply for a different price path to fund recovery.	An extreme disruptive event resulting in destruction of significant parts of WELL's network would require elements of this Plan to be revised.

Appendix B Update from 2023 Plan

Material Progress and Changes Since Previous Plan

During the past year, WELL has continued the review of its asset management strategy and practices. Progress against the gaps identified in the 2023 AMP, along with progress and material changes to network development projects and lifecycle asset management plans, is shown in the Table B-1.

2024 AMP Section	Item	Description
3.2.5.4	People and Culture Group	**Update:** WELL has established a new People and Culture Group, reporting to the Chief Executive. This Group is responsible for QSE, Human Resources, and ESG.
7.1	Reliability Performance Targets	**Update:** WELL has updated its Planned SAIDI and Planned SAIFI targets for the planning period, and listed the assumptions behind the forecast.
7.3.2	Reliability Trend Analysis	**Update:** A new section has been added discussing WELL's methodology for assessing trends in SAIDI by outage type.
7.3.3	Wind Effect Normalisation	**Update:** A new section has been added discussing the normalisation of overhead network performance to wind conditions.
7.4.3	Risk-based Vegetation Control	**Update:** A new section has been added discussing WELL's approach to vegetation maintenance.
8.5.1	Subtransmission Cable Renewal	**Update:** The Titahi Bay fluid-filled cables (operated at 11kV) have been brought forward in the renewal programme, with replacement now planned to be completed by 2026 in coordination with a city council urban cycleway project. The replacement of the Tawa fluid-filled cables is now expected to occur in 2026 as a System Growth project.
8.5.2	Power Transformer Renewal	**Update:** The replacement of the Tawa transformers is now expected to occur in 2026 as a System Growth project. The replacement of the Mana transformer is now expected to occur in 2033/34.
8.5.4	Distribution and LV Cables	**Update:** WELL's intention regarding the commencement of the large-scale renewal of its distribution and LV cable fleets is discussed.

2024 AMP Section	Item	Description
9	Public Transport Traction Projects	**Update:** Projects to support new public transport traction load that was classified as large customer project reopeners in Section 13.7 of the 2023 AMP have been moved into System Growth in the 2024 AMP due to their impact on network capacity headroom and delays in the projects meaning they no longer need to be funded through a reopening of DPP3.
9.4.2.1	Ira Street zone substation capacity	**2023 AMP:** The preferred option for resolving this constraint is to shift load from Ira Street to a new zone substation to be developed in the Miramar Peninsula.
		Update: New customer requirements have meant that an upgrade to Ira Street zone substation is now required.
9.5.2.1	Johnsonville zone substation capacity	**2023 AMP:** WELL plans to replace the Johnsonville 33kV cables and transformers by 2031.
		Update: The upgrade of Johnsonville can be delayed as a result of the construction of the Grenada zone substation.
9.5.2.4	Mana zone substation capacity	**2023 AMP:** Mana will be disestablished when the new Plimmerton zone substation is constructed.
		Update: Mana will still be required after the construction of the new Plimmerton zone substation. WELL plans to upgrade the Mana-Plimmerton 11kV tie to resolve the constraint.
9.5.2.7	Tawa zone substation capacity	**2023 AMP:** The Tawa subtransmission cables and transformers are planned for replacement due to asset health in 2030.
		Update: Significant load growth is expected from public transport electrification upgrades in the area, with further growth resulting from the Grenada North industrial area and new residential developments in Grenada. The preferred option for resolving this constraint is replacement of the Tawa subtransmission cables and transformers in 2026.
9.6.2.9	Trentham zone substation capacity	**2023 AMP:** WELL plans to build another zone substation in the area, to be fed from Upper Hutt GXP, and offload Trentham
		Update: The new substation will initially be developed as an 11kV switching station, with the ability to be developed into a full zone substation when required.

2024 AMP Section	Item	Description
9.7	LV CAPEX Forecast	**Update:** WELL has developed a LV reinforcement CAPEX forecast based on 30-year residential decarbonisation load growth forecasts. This forecast has been added to the System Growth CAPEX of the 2024 AMP.
10.3.4.4	Resi-Flex	**Update:** An update on the Resi-Flex trial is provided.
10.4.1	Change in Opex needed to support the work programme	**Update:** WELL has provided the assumptions behind its forecast of OPEX growth and step changes needed to deliver the CAPEX programme and support the integration of flexibility services.
12.4.3	Resilience Risks	**Update:** WELL has provided a summary of its primary network resilience risks, and the actions underway to address them.
13.7	Reopeners For Large New Connections	**2023 AMP:** WELL is preparing two applications to the Commission for additional allowances using the reopener for large new connections.
		Update: The customers have advised that these projects have been delayed until the next regulatory period, and it is therefore no longer necessary to apply for a reopener in DPP3 to fund these projects.

Table B-1 Material Changes in the 2024 AMP

Comparison of Financial Performance to Previous Plan

Comparisons between forecast expenditure from the 2023 AMP and the actual expenditure for the 2023/24 regulatory year are shown below in Table B-2 for operational expenditure and Table B-3 for capital expenditure.

Expenditure Category	2023/24 Forecast from 2023 AMP	2023/24 Actuals	Variation
Service Interruptions and Emergencies	4,172	4,284	112
Vegetation Management	2,023	1,642	(381)
Routine and Corrective Maintenance and Inspection	9,449	9,771	322
Asset Replacement and Renewal	1,199	1,201	2
System Operations and Network Support	8,118	8,984	866
Business Support	13,101	12,528	(573)
Operational Expenditure	**38,064**	**38,411**	**347**

Table B-2 Comparison of Operational Expenditure against 2023 AMP Forecasts
($K, forecast in nominal dollars)

Operating expenditure was approximately in line with forecast. The difference between System Operations and Network Support and Business Support costs was due to a classification of information and technology costs.

Expenditure Category	2023/24 Forecast from 2023 AMP	2023/24 Actuals	Variation
Customer Connection	13,161	21,455	8,294
System Growth	6,836	4,904	(1,932)
Asset Replacement and Renewal	28,518	30,102	1,584
Asset Relocations	784	8,506	7,722
Reliability, Safety and Environment	3,535	2,513	(1,022)
Expenditure on Non-network Assets	12,618	2,299	(10,319)
Capital Expenditure	**65,452**	**69,778**	**4,326**

Table B-3 Comparison of Capital Expenditure against 2023 AMP Forecasts
($K, forecast in nominal dollars)

Capital expenditure was approximately 7% higher than forecast, with variances primarily due to Customer Connection spend being higher than the forecast. This was due to a greater than forecast value of customer-initiated projects occurring during the year. Customer contribution revenue also increased in line with the increases in Customer Connection and Asset Relocation capital expenditure. The Data Centre Relocation was under Non-network Assets in the 2023 AMP but is now categorised under Asset Relocations. This change is to align with WELL's reopener application to fund this project. Differences to the System Growth and Asset Replacement and Renewal programmes were due to refinements in project plans, with projects being resequenced between the categories with no material net impact.

Appendix C Schedules

Company Name	Wellington Electricity
AMP Planning Period	1 April 2024 – 31 March 2034

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary 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												
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	21,455	14,687	18,816	19,193	19,576	19,968	18,033	18,394	18,761	19,137	19,519
11	System growth	4,904	2,822	68,370	201,690	176,604	177,638	145,772	77,806	56,926	21,191	19,955
12	Asset replacement and renewal	30,102	31,105	45,103	32,311	40,117	41,138	30,007	42,305	43,020	44,669	38,916
13	Asset relocations	8,506	1,511	823	856	891	927	965	1,003	1,043	1,085	1,107
14	Reliability, safety and environment:											
15	Quality of supply	2,012	2,517	2,662	2,716	2,770	2,825	2,882	2,940	2,998	3,058	3,120
16	Legislative and regulatory	-	-	4,748	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	501	753	2,620	706	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**	2,513	3,270	10,030	3,422	2,770	2,825	2,882	2,940	2,998	3,058	3,120
19	**Expenditure on network assets**	67,479	53,395	143,142	257,471	239,959	242,496	197,659	142,447	122,749	89,140	82,616
20	Expenditure on non-network assets	2,299	4,642	39,397	1,825	3,573	2,147	1,954	3,586	1,613	1,407	1,666
21	**Expenditure on assets**	69,778	58,037	182,539	259,296	243,532	244,644	199,613	146,033	124,362	90,547	84,282
22												
23	*plus* Cost of financing	377	325	1,050	1,522	1,458	1,494	1,243	928	806	598	568
24	*less* Value of capital contributions	16,348	10,832	23,333	14,034	14,327	14,626	14,919	15,217	15,522	15,832	16,149
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	53,807	47,530	160,257	246,784	230,663	231,511	185,937	131,744	109,647	75,313	68,702
28												
29	Assets commissioned	46,504	55,530	160,257	246,784	230,663	231,511	185,937	131,744	109,647	75,313	68,702

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												
32		**$000 (in constant prices)**										
33	Consumer connection	21,455	14,150	17,668	17,668	17,668	17,668	15,643	15,643	15,643	15,643	15,643
34	System growth	4,904	2,719	64,198	185,669	159,388	157,178	126,453	66,171	47,464	17,322	15,992
35	Asset replacement and renewal	30,102	29,966	42,351	29,745	36,207	36,400	26,030	35,978	35,869	36,514	31,187
36	Asset relocations	8,506	1,456	773	788	804	820	837	853	870	887	887
37	Reliability, safety and environment:											
38	Quality of supply	2,012	2,425	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
39	Legislative and regulatory	-	-	4,458	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	501	725	2,460	650	-	-	-	-	-	-	-
41	**Total reliability, safety and environment**	2,513	3,150	9,418	3,150	2,500	2,500	2,500	2,500	2,500	2,500	2,500
42	**Expenditure on network assets**	67,479	51,440	134,407	237,020	216,567	214,565	171,463	121,146	102,346	72,866	66,209
43	Expenditure on non-network assets	2,299	4,472	36,993	1,680	3,225	1,900	1,695	3,050	1,345	1,150	1,335
44	**Expenditure on assets**	69,778	55,912	171,400	238,700	219,792	216,465	173,158	124,196	103,691	74,016	67,544
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
48	Energy efficiency and demand side management, reduction of energy losses											
49	Overhead to underground conversion											
50	Research and development											
51	Cybersecurity (Commission only)											
52												

Difference between nominal and constant price forecasts

$000	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Consumer connection	-	538	1,148	1,525	1,908	2,300	2,390	2,751	3,118	3,494	3,876
System growth	-	103	4,172	16,021	17,216	20,460	19,319	11,635	9,462	3,869	3,963
Asset replacement and renewal	-	1,139	2,752	2,567	3,911	4,738	3,977	6,326	7,151	8,155	7,728
Asset relocations	-	55	50	68	87	107	128	150	173	198	220
Reliability, safety and environment:											
Quality of supply	-	92	162	216	270	325	382	440	498	558	620
Legislative and regulatory	-	-	290	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	28	160	56	-	-	-	-	-	-	-
Total reliability, safety and environment	-	120	612	272	270	325	382	440	498	558	620
Expenditure on network assets	-	1,955	8,735	20,452	23,392	27,931	26,196	21,301	20,403	16,274	16,407
Expenditure on non-network assets	-	170	2,404	145	348	247	259	536	268	257	331
Expenditure on assets	-	2,125	11,139	20,597	23,740	28,178	26,455	21,838	20,671	16,531	16,738

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

*Consumer types defined by EDB** — $000 (in constant prices)	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Substation	10,334	6,815	9,326	9,326	9,326	9,326
Subdivision	6,803	4,487	5,103	5,103	5,103	5,103
High Voltage Connection	3,808	2,511	2,856	2,856	2,856	2,856
Residential Customers	468	309	351	351	351	351
Public Lighting	43	28	32	32	32	32
**include additional rows if needed*						
Consumer connection expenditure	21,455	14,150	17,668	17,668	17,668	17,668
less Capital contributions funding consumer connection	15,752	9,905	12,368	12,368	12,368	12,368
Consumer connection less capital contributions	5,703	4,245	5,300	5,300	5,300	5,300

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	3,268	439	-	42,890	15,000	-
Zone substations		-	6,000	107,691	90,000	54,000
Distribution and LV lines		-	200	200	200	200
Distribution and LV cables	1,216	2,280	45,398	22,288	41,088	90,378
Distribution substations and transformers	166	-	12,600	12,600	12,600	12,600
Distribution switchgear		-	-	-	-	-
Other network assets	254	-	-	-	500	-
System growth expenditure	4,904	2,719	64,198	185,669	159,388	157,178
less Capital contributions funding system growth	-	-	9,000	-	-	-
System growth less capital contributions	4,904	2,719	55,198	185,669	159,388	157,178

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
Subtransmission	-	1,512	12,500	-	8,500	10,000
Zone substations	3,010	2,460	470	470	470	470
Distribution and LV lines	7,516	7,142	7,250	7,268	7,145	7,075
Distribution and LV cables	3,465	2,705	2,734	2,734	3,206	3,206
Distribution substations and transformers	5,074	5,486	5,317	5,317	5,537	5,262
Distribution switchgear	6,124	6,161	9,518	9,982	6,777	6,537
Other network assets	4,913	4,500	4,562	3,974	4,572	3,850
Asset replacement and renewal expenditure	30,102	29,966	42,351	29,745	36,207	36,400
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	30,102	29,966	42,351	29,745	36,207	36,400

11a(v): Asset Relocations

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
General capex	1,203	758	773	788	804	820
Disaster Recovery Site Relocation	7,302	698	-	-	-	-
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	8,506	1,456	773	788	804	820
less Capital contributions funding asset relocations	596	531	541	552	563	574
Asset relocations less capital contributions	7,909	925	232	236	241	246

11a(vi): Quality of Supply

*Project or programme**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	$000 (in constant prices)					
Feeder Reliability Improvement - Lines	1,409	875	1,100	1,100	1,100	1,100
Feeder Reliability Improvement - Switchgear	603	1,550	1,200	1,200	1,200	1,200
Switchgear SCADA Control Retrofit	-	-	200	200	200	200
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	2,012	2,425	2,500	2,500	2,500	2,500
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	2,012	2,425	2,500	2,500	2,500	2,500

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
141		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
142	**11a(vii): Legislative and Regulatory**						
143	*Project or programme**	$000 (in constant prices)					
144	AUFLS Relay Replacement	-	-	4,458	-	-	-
145							
146							
147							
148	**include additional rows if needed*						
149	All other projects or programmes - legislative and regulatory						
150	**Legislative and regulatory expenditure**	-	-	4,458	-	-	-
151	*less* Capital contributions funding legislative and regulatory						
152	**Legislative and regulatory less capital contributions**	-	-	4,458	-	-	-
153							
154		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
155	**11a(viii): Other Reliability, Safety and Environment**						
156	*Project or programme**	$000 (in constant prices)					
157	Seismic Strengthening	501	725	460	650	-	-
158	Generator connection switchgear		-	2,000	-	-	-
159							
160							
161	**include additional rows if needed*						
162	All other projects or programmes - other reliability, safety and environment						
163	**Other reliability, safety and environment expenditure**	501	725	2,460	650	-	-
164	*less* Capital contributions funding other reliability, safety and environment						
165	**Other reliability, safety and environment less capital contributions**	501	725	2,460	650	-	-
166							
167		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
168	**11a(ix): Non-Network Assets**						
169	**Routine expenditure**						
170	*Project or programme**	$000 (in constant prices)					
171	Software and Licenses	1,641	1,858	2,348	565	1,360	515
172	IT Infrastructure	501	614	2,245	515	1,265	785
173	Future Services	158	-	2,400	600	600	600
174	Storage site leases		2,000				
175	**include additional rows if needed*						
176	All other projects or programmes - routine expenditure						
177	**Routine expenditure**	2,299	4,472	6,993	1,680	3,225	1,900
178	**Atypical expenditure**						
179	*Project or programme**						
180	Office Relocation	-	-	30,000	-	-	-
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	30,000	-	-	-
187							
188	**Expenditure on non-network assets**	2,299	4,472	36,993	1,680	3,225	1,900
189							

Company Name	Wellington Electricity
AMP Planning Period	1 April 2024 – 31 March 2034

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). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this may be disclosed in Schedule 15 (Voluntary Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8												
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	4,284	5,490	5,632	5,745	5,860	5,977	6,097	6,219	6,343	6,470	6,599
11	Vegetation management	1,642	2,349	2,610	2,662	2,716	2,770	2,825	2,882	2,940	2,998	3,058
12	Routine and corrective maintenance and inspection	9,771	11,362	11,657	11,890	12,128	12,371	12,618	12,871	13,128	13,391	13,658
13	Asset replacement and renewal	1,201	1,525	1,565	1,596	1,628	1,661	1,694	1,728	1,763	1,798	1,834
14	**Network Opex**	16,898	20,726	21,465	21,894	22,332	22,779	23,234	23,699	24,173	24,657	25,150
15	System operations and network support	8,984	10,556	13,138	13,861	14,490	14,783	15,288	15,594	15,906	16,224	16,548
16	Business support	12,528	13,207	16,437	17,341	18,128	18,495	19,127	20,266	21,519	22,901	24,426
17	**Non-network opex**	21,513	23,762	29,575	31,202	32,618	33,278	34,416	35,860	37,425	39,124	40,974
18	**Operational expenditure**	38,411	44,488	51,040	53,096	54,950	56,057	57,650	59,559	61,598	63,781	66,124
19		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20												
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	4,284	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289	5,289
23	Vegetation management	1,642	2,263	2,451	2,451	2,451	2,451	2,451	2,451	2,451	2,451	2,451
24	Routine and corrective maintenance and inspection	9,771	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946	10,946
25	Asset replacement and renewal	1,201	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
26	**Network Opex**	16,898	19,967	20,155	20,155	20,155	20,155	20,155	20,155	20,155	20,155	20,155
27	System operations and network support	8,984	10,169	12,336	12,760	13,077	13,080	13,262	13,262	13,262	13,262	13,262
28	Business support	12,528	12,723	15,434	15,964	16,361	16,365	16,592	17,235	17,942	18,720	19,575
29	**Non-network opex**	21,513	22,893	27,770	28,724	29,438	29,445	29,855	30,497	31,204	31,982	32,837
30	**Operational expenditure**	38,411	42,859	47,926	48,879	49,593	49,600	50,010	50,652	51,359	52,137	52,992
31	**Subcomponents of operational expenditure (where known)**											
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
32–33	Energy efficiency and demand side management, reduction of energy losses	-	-	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	2,778	3,195	3,675	4,226	4,860	5,588	6,427	7,069	7,776	8,554	9,409
37	Cybersecurity (Commission only)											
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
39												
40		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
41												
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	201	344	456	571	688	808	930	1,054	1,181	1,311
44	Vegetation management	-	86	159	211	265	319	374	431	489	547	607
45	Routine and corrective maintenance and inspection	-	416	711	945	1,182	1,425	1,672	1,925	2,182	2,445	2,712
46	Asset replacement and renewal	-	56	96	127	159	191	225	258	293	328	364
47	**Network Opex**	-	759	1,310	1,739	2,177	2,624	3,079	3,544	4,018	4,501	4,995
48	System operations and network support	-	386	802	1,101	1,412	1,703	2,026	2,332	2,644	2,962	3,286
49	Business support	-	483	1,003	1,377	1,767	2,130	2,535	3,031	3,577	4,181	4,851
50	**Non-network opex**	-	870	1,805	2,478	3,180	3,833	4,561	5,362	6,221	7,143	8,137
51	**Operational expenditure**	-	1,629	3,115	4,218	5,357	6,457	7,640	8,906	10,238	11,644	13,132
52												
53	**Commentary on options and considerations made in the assessment of forecast expenditure**											
54	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*											
55												

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Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.23%	27.25%	31.90%	38.83%	1.80%	3	1.42%
11	All	Overhead Line	Wood poles	No.	0.05%	2.67%	61.29%	19.75%	13.10%	3.13%	3	17.99%
12	All	Overhead Line	Other pole types	No.	-	-	0.85%	0.85%	98.31%	-	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	13.81%	59.41%	21.32%	5.46%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	7.09%	-	55.64%	37.27%	-	3	7.09%
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	18.62%	81.38%	-	-	-	3	32.10%
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	11.39%	13.74%	74.87%	-	-	-	3	36.46%
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	1.04%	56.08%	42.88%	-	-	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%	-	-	-	3	100.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	-	-	-	N/A	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	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.	-	16.12%	63.39%	2.46%	18.03%	-	3	11.20%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	
35												

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					Asset condition at start of planning period (percentage of units by grade)							
	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.	-	7.69%	65.38%	26.92%	-	-	4	15.38%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.31%	13.86%	72.40%	8.79%	4.64%	-	3	3.40%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	39.00%	20.17%	0.12%	40.71%	-	3	-
42	HV	Distribution Line	SWER conductor	km	-	-	100.00%	-	-	-	3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	1.23%	34.34%	64.43%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	0.03%	9.07%	67.81%	22.95%	0.14%	-	3	0.16%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	100.00%	-	-	-	3	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	5.56%	16.67%	50.00%	27.78%	-	3	5.56%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	1.52%	70.32%	28.16%	-	-	3	7.72%
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	0.69%	65.45%	18.15%	15.70%	-	3	7.68%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	49.65%	47.92%	2.43%	-	-	3	34.03%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	1.31%	81.35%	11.66%	5.68%	-	3	3.64%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.05%	1.15%	56.37%	26.26%	16.15%	-	3	16.10%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	0.41%	74.46%	19.83%	5.30%	-	3	8.25%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	-	N/A	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	1.35%	57.70%	35.36%	5.60%	-	3	6.17%
55	LV	LV Line	LV OH Conductor	km	0.50%	15.46%	79.89%	3.06%	1.08%	-	2	0.93%
56	LV	LV Cable	LV UG Cable	km	0.04%	3.89%	71.49%	15.92%	8.66%		2	0.28%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.05%	5.41%	79.68%	11.11%	3.75%		2	0.25%
58	LV	Connections	OH/UG consumer service connections	No.	0.05%	6.89%	82.85%	9.75%	0.46%	-	1	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	0.21%	1.79%	82.12%	5.16%	10.73%	-	3	6.60%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	11.99%	36.33%	10.86%	20.22%	20.60%	-	3	33.71%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	
62	All	Load Control	Centralised plant	Lot	-	24.00%	60.00%	-	16.00%	-	3	24.00%
63	All	Load Control	Relays	No.	-	-	-	-	-	-	N/A	
64	All	Civils	Cable Tunnels	km	-	-	100.00%	-	-	-	3	-

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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	8 Ira Street	16	18	N-1	8	90%	20	152%	Transformer	Subtransmission cable upgrade in 2027. Transformer upgrade planned for 2030.
10	Brown Owl	16	18	N-1	9	87%	16	121%	Subtransmission circuit	Monitor load growth and develop response.
11	Evans Bay	13	19	N-1	7	66%	24	89%	No constraint within +5 years	Transformer replacement in 2024. Subtransmission cable upgrade in 2027
12	Frederick Street	26	30	N-1	11	86%	30	95%	No constraint within +5 years	Load transfer to proposed new Newtown ZS from 2026
13	Gracefield	11	23	N-1	11	48%	23	93%	No constraint within +5 years	
14	Hataitai	16	21	N-1	9	75%	21	84%	No constraint within +5 years	
15	Johnsonville	20	16	N-1	6	125%	16	63%	No constraint within +5 years	Load transfer to proposed new Grenada North ZS from 2028
16	Karori	14	20	N-1	5	72%	20	92%	No constraint within +5 years	
17	Kenepuru	11	18	N-1	8	61%	18	96%	No constraint within +5 years	
18	Korokoro	19	16	N-1	15	123%	16	93%	No constraint within +5 years	Remove 33 kV subtransmisison cable and transformer constraint through redevelopment of Petone substation
19	Maidstone	15	18	N-1	10	84%	18	85%	No constraint within +5 years	New switching station to manage load
20	Mana	9	7	N-1	11	129%	14	89%	No constraint within +5 years	Upgrade Mana-Plimmerton bus tie in 2028
21	Moore Street	18	30	N-1	12	60%	30	77%	No constraint within +5 years	
22	Naenae	15	18	N-1	10	82%	18	102%	Subtransmission circuit	Monitor load growth and develop response.
23	Nairn Street	22	22	N-1	14	100%	22	88%	No constraint within +5 years	Load transfer to proposed new Newtown ZS from 2026
24	Ngauranga	11	10	N-1	8	110%	36	67%	No constraint within +5 years	Transformer upgrade planned for 2026
25	Palm Grove	24	20	N-1	10	120%	20	86%	No constraint within +5 years	Load transfer to proposed new Newtown ZS from 2026
26	Plimmerton	8	7	N-1	9	114%	22	40%	No constraint within +5 years	Build new Plimmerton ZS in 2027
27	Porirua	22	16	N-1	12	136%	36	92%	No constraint within +5 years	Substation rebuild planned for 2026
28	Seaview	15	14	N-1	10	109%	14	87%	No constraint within +5 years	Remove 33 kV subtransmisison cable and transformer constraint through redevelopment of Petone substation
29	Tawa	15	16	N-1	13	91%	36	61%	No constraint within +5 years	Substation rebuild planned for 2026
30	The Terrace	23	30	N-1	16	77%	30	87%	No constraint within +5 years	
31	Trentham	17	19	N-1	8	87%	19	92%	No constraint within +5 years	New switching station to manage load
32	University	18	20	N-1	17	89%	20	103%	Transformer	Monitor load growth and develop response.
33	Waikowhai Street	14	15	N-1	8	91%	15	100%	Subtransmission circuit	Monitor load growth and develop response.
34	Wainuiomata	17	20	N-1	3	85%	20	101%	Transformer	Monitor load growth and develop response.
35	Waitangirua	14	16	N-1	9	88%	16	114%	Transformer	Transformer upgrade planned for 2030
36	Waterloo	17	20	N-1	12	85%	20	113%	Subtransmission circuit	Monitor load growth and develop response.

37 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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 during year by consumer type*			**Number of connections**			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10							
11	*Consumer types defined by EDB**						
12	Domestic	1,829	1,911	1,928	2,062	2,081	2,100
13	Small Commercial	469	613	619	662	668	674
14	Medium Commercial	14	20	20	21	22	22
15	Large Commercial	19	15	15	16	16	17
16	Small Industrial	12	17	17	18	19	19
17	Large Industrial	-	1	1	1	1	1
18	Unmetered	16	1	1	1	1	1
19	**Connections total**	2,359	2,578	2,602	2,782	2,807	2,833
20	**include additional rows if needed*						
21							
22							
23							
24	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
25	Number of connections made in year	616	764	979	1,255	1,609	2,065
26	Capacity of distributed generation installed in year (MVA)	4	4	5	6	8	10
27	**12c(ii) System Demand**						
28		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
29	**Maximum coincident system demand (MW)**						
30	GXP demand	478	521	565	593	614	635
31	*plus* Distributed generation output at HV and above	58	58	58	58	58	58
32	**Maximum coincident system demand**	536	579	623	651	672	693
33	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
34	**Demand on system for supply to consumers' connection points**	536	579	623	651	672	693
35	**Electricity volumes carried (GWh)**						
36	Electricity supplied from GXPs	2,256	2,657	2,922	3,093	3,240	3,349
37	*less* Electricity exports to GXPs	85	85	85	85	85	85
38	*plus* Electricity supplied from distributed generation	228	228	228	228	228	228
39	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
40	**Electricity entering system for supply to ICPs**	2,399	2,800	3,065	3,236	3,383	3,492
41	*less* Total energy delivered to ICPs	2,315	2,702	2,958	3,123	3,265	3,370
42	**Losses**	84	98	107	113	118	122
43							
44	**Load factor**	51%	55%	56%	57%	58%	58%
45	**Loss ratio**	3.5%	3.5%	3.5%	3.5%	3.5%	3.5%
46							

safer together

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2024 – 31 March 2034**
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							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	11.3	12.2	17.1	17.0	16.4	15.9
12	Class C (unplanned interruptions on the network)	32.1	31.2	31.2	31.2	31.2	31.2
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.07	0.07	0.10	0.10	0.09	0.09
15	Class C (unplanned interruptions on the network)	0.41	0.48	0.48	0.48	0.48	0.48

safer together

Company Name	**Wellington Electricity**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	WELL has an Asset Management Policy which is derived from the organisational vision and linked to the organisational strategies, objectives and targets. WELL has also published an Asset Management Strategy (AM Strategy) and associated Fleet Strategies for discrete assets.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	All key components of WELL's AM Strategy are covered in the AMP. Development of Fleet Strategies as well as the overarching AM Strategy has taken into consideration alignment with other organistaional policies and key stakeholders and has had peer review undertaken by industry experts.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	An Asset Management Strategy has been published to cover the total management of assets. Asset Fleet Strategies have been developed for primary asset classes.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Flowing on from the abovementioned Asset Fleet Strategies, WELL has put in place comprehensive asset management plans (fleet strategies) that cover all lifecycle activities of the key asset classes, aligned to asset management objectives and strategies.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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AMP Planning Period	1 April 2024 – 31 March 2034
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 2024 – 31 March 2034**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The plan is communicated to all relevant employees, stakeholders, and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan, and there is confirmation that they are being used effectively. All asset strategies are published as controlled documents.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The asset management plan documents responsibilities for the delivery actions, and appropriate detail is provided to enable delivery of these actions. Roles and responsibilities of individuals and organisational departments are defined.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	WELL is developing a Project Management Office (PMO) that will manage the outsourced project management of large projects. The outsourced work packages will include end-to-end design and construction. Coupled with this WELL is engaging with a broader range of electrical contractors to enable them to build the skills and teams necessary to deliver the work plan.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	WELL has a suite of appropriate Emergency Response Procedures and Contingency Plans in place to mitigate and manage the impact of potential High Impact Low Probability events. These are listed and described in Section 12 of this AMP. These plans get tested in simulated major event situations.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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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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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Accountability for asset management responsibility flows from the CEO through the GM Asset Management, to the functional Line Managers.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Top management recognise that a step change in investment is required under the ERP, and has developed a delivery strategy in response. This includes the need for additional resources and new capability above current levels.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Communication is guided through the the annual AMP disclosures, and through weekly and monthly meetings with management teams and service providers.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	WELL outsources a number of asset management activities, particularly with Service Delivery responsibilities. These are described in Section 5 of this AMP. Comprehensive contracts and performance measures are in place to ensure efficient and cost-effective delivery of these activities.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	WELL can demonstrate that role descriptions are in place for all staff required to conduct asset management functions, and that these roles are filled with appropriately qualified personnel.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Position descriptions are in place for all staff required to conduct asset management functions. Staff undertake training and development where required to ensure they can deliver on the requirements of the AMP. Work competencies are listed for all main contracting activities, and WELL monitors and ensures that the Contractors' staff have, and maintain their competencies.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Training requirements are identified at the start of the year, and reviewed every six months during staff performance reviews. Work competencies are listed for all main contracting activities, and WELL monitors and ensures that the Contractors' staff have, and maintain their competencies.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	In addition to the annual AMP disclosure, regular contract meetings are held between Safety, Asset Management and Service Delivery Managers and the respective service providers. In addition specific asset management is communicated between employees and contractors through safety alerts, technical alerts, network instructions, and at technical forums.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Asset Management documentation and control is in place, and is described in Section 5 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?	2	WELL recognises that it needs additional asset management information systems for the new data needed to support asset management under the ERP, and needs to develop systems and processes to manage those. WELL undertook an Asset Information Maturity Assessment in 2023, and is developing a work programme that will ensure that asset information improvement investment is allocated to where it will deliver the most value.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Contols are are place in the form of data quality standards to manage the quality and accuracy of the data entered into the asset management information systems. Processes for QA and audit of data are in place.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	In addition to the annual AMP disclosure, regular contract meetings are held between Safety, Asset Management and Service Delivery Managers and the respective service providers. In addition specific asset management is communicated between employees and contractors through safety alerts, technical alerts, network instructions, and at technical forums.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Asset Management documentation and control is in place, and is described in Section 5 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?	2	WELL recognises that it needs additional asset management information systems for the new data needed to support asset management under the ERP, and needs to develop systems and processes to manage those. WELL undertook an Asset Information Maturity Assessment in 2023, and is developing a work programme that will ensure that asset information improvement investment is allocated to where it will deliver the most value.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Contols are are place in the form of data quality standards to manage the quality and accuracy of the data entered into the asset management information systems. Processes for QA and audit of data are in place.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Asset Management requirements were fully reviewed during development of the business cases to implement SAP-PM and to upgrade GIS, ensuring that they meet Asset Management needs. The systems have been reviewed at various times by CHED auditors, Jacobs, PwC, and other external specialists.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	In January 2016, WELL aligned its risk approach with that of CKI by adopting the Enterprise Risk Management (ERM) – Integrated Framework Risk Management Principles and Guidelines Standard. This provides a structured and robust framework to managing risk, which is applied to all business activities.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Outputs from risk assessments are fed back into standards, procedures and training through the actions resulting from various meetings and other communications.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	WELL has staff in its office that are responsible for Legal, Regulatory, Statutory and other asset management requirements.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Consultants are often used to assist during the design stage. Scope of work is clearly defined and controlled through a Short Form Agreement. Procurement is controlled through an approved materials standard. Construction and commissioning activities are outsourced, and these are carefully controlled through contracts with the service providers.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	There is an inspection and maintenance plan in place with remedial actions derived from the prioritisation of critical defects. Ongoing training is carried out to standardise the level of consistency across the inspection and condition assessment process, and how the results are then optimised within the maintenance planning function. These plans are reviewed and optimised on an annual basis.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	WELL annually rates all primary 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 update of the Fleet Strategies and replacement programmes.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	WELL has procedures which clearly outline the roles and responsibilities for managing major incidents and emergency situations. The Asset Failure investigation standard describes the process and responsibilities for investigating asset-related failures.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	CKI has internal auditors in CHED Services in Melbourne that select two areas to do comprehensive audits on each year. Further to this WELL has had its Asset Management activities and processes reviewed by Jacobs with a positive outcome and report.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Incident and root cause analysis investigations and corrective actions involve both WELL and its service providers, and are logged, reviewed and discussed at weekly meetings. The 1Fics software package 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?	3	The Asset Fleet Strategies detail asset-specific strategies for meeting the asset management objectives. These documents analyse the performance, and condition of assets across the whole life cycle, as well as maintenance and replacement costs, and any associated asset-related risks. They are controlled documents on an annual review cycle, with this update process ensuring that continual improvement in the management of asset performance, condition, costs, and risks.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Being part of a wider international group, WELL places a high level of importance on learnings that can be made from its sister companies within the group, and from within the industry in New Zealand. There are video conferences held between sister companies to discuss the latest in AM practices from across the world.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 6 July 2023)

This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

There is no difference between constant and nominal values in the current disclosure year ended 31 March 2024.

The difference from 2024/25 to 2033/34 represents inflation. Inflation is based on the Reserve Bank February 2024 Monetary Policy Forecast (https://www.rbnz.govt.nz/hub/-/media/project/sites/rbnz/files/publications/monetary-policy-statements/2024/mps-feb-24.pdf).

2024	2025	2026	2027- 2034
3.8%	2.6%	2.0%	2.0%

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 2024.

The difference from 2024/25 to 2033/34 represents inflation. Inflation is based on the Reserve Bank February 2024 Monetary Policy Forecast (https://www.rbnz.govt.nz/hub/-/media/project/sites/rbnz/files/publications/monetary-policy-statements/2024/mps-feb-24.pdf).

2024	2025	2026	2027- 2034
3.8%	2.6%	2.0%	2.0%

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	5.1, 5.2
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the **AMP** in the **EDB**'s asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	2.1
3.3.2 states the corporate mission or vision as it relates to asset management	3.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the **EDB**	5.1
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	6.1
3.3.5 includes a description of the interaction between the objectives of the **AMP** and other corporate goals, business planning processes, and plans	3.1
3.4 Details of the **AMP planning period**, which must cover at least a projected period of 10 years commencing with the **disclosure year** following the date on which the **AMP** is disclosed	2
3.5 The date that it was approved by the **directors**	2
3.6 A description of stakeholder interests (owners, **consumers** etc.) which identifies important stakeholders and indicates-	
3.6.1 how the interests of stakeholders are identified	3.6.1
3.6.2 what these interests are	3.6.1
3.6.3 how these interests are accommodated in asset management practices	3.6.1
3.6.4 how conflicting interests are managed	3.6.2

Information Disclosure Requirements 2012 clause	AMP section
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1 governance—a description of the extent of **director** approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to **directors**	3.2.2, 3.2.4.1
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured	3.2.3 & 3.2.5
3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	3.2.5 & 4.3.1
3.8 All significant assumptions:	
3.8.1 quantified where possible	Appendix A
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including	Appendix A
3.8.3 a description of changes proposed where the information is not based on the **EDB**'s existing business	Appendix A
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information	Appendix A
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in **nominal New Zealand dollars** in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Schedule 14a
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	1.3-1.4, 4 & Appendix A
3.10 An overview of asset management strategy and delivery	5.1, 5.3

Information Disclosure Requirements 2012 clause	AMP section
3.11 An overview of systems and information management data	11.1
3.11.1 To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe:	
(a) the processes used to identify asset management data requirements that cover the whole of life cycle of the assets;	
(b) the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;	
(c) the systems and controls to ensure the quality and accuracy of asset management information;	
(d) the extent to which these systems, processes and controls are integrated;	
(e) how asset management data informs the models that an EDB develops and uses to assess asset health; and	8.3
(f) how the outputs of these models are used in developing capital expenditure projections.	8.3, 8.5
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	11.3
3.13 A description of the processes used within the **EDB** for-	
3.13.1 managing routine asset inspections and **network** maintenance	8.4, 11.1.1.10
3.13.2 planning and implementing **network** development projects	9.2
3.13.3 measuring **network** performance.	6.2.2
3.14 An overview of asset management documentation, controls and review processes	5.4
3.15 An overview of communication and participation processes	3.6, 5.1
3.16 The **AMP** must present all financial values in **constant price New Zealand dollars** except where specified otherwise;	2.4
3.17 The **AMP** must be structured and presented in a way that the **EDB** considers will support the purposes of **AMP** disclosure set out in clause 2.6.1(3) of the determination.	Yes

Information Disclosure Requirements 2012 clause	AMP section
<u>Assets Covered</u>	
4. The **AMP** must provide details of the assets covered, including-	3.3
4.1 a high-level description of the service areas covered by the **EDB** and the degree to which these are interlinked, including-	3.4
4.1.1 the region(s) covered	3.5
4.1.2 identification of large **consumers** that have a significant impact on network operations or asset management priorities	3.5 & 9.2
4.1.3 description of the load characteristics for different parts of the **network**	3.5
4.1.4 peak demand and total energy delivered in the previous year, broken down by **sub-network**, if any.	
4.2 a description of the **network** configuration, including-	
4.2.1 identifying bulk electricity supply points and any **distributed generation** with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	3.4
4.2.2 a description of the **subtransmission** system fed from the bulk electricity supply points, including the capacity of **zone substations** and the voltage(s) of the **subtransmission network**(s). The **AMP** must identify the supply security provided at individual **zone substations**, by describing the extent to which each has n-x **subtransmission** security or by providing alternative security class ratings;	3.4, 9.4–9.6
4.2.3 a description of the distribution system, including the extent to which it is underground;	3.4, 8.5.4
4.2.4 a brief description of the **network**'s distribution substation arrangements;	3.4, 8.5.5
4.2.5 a description of the **low voltage network** including the extent to which it is underground; and	3.4, 8.5.4
4.2.6 an overview of **secondary assets** such as protection relays, ripple injection systems, SCADA and telecommunications systems.	8.5.8
4.3 If **sub-networks** exist, the **network** configuration information referred to in subclause 4.2 above must be disclosed for each **sub-network**.	N/A
<u>Network Assets by Category</u>	
4.4 The **AMP** must describe the **network** assets by providing the following information for each asset category-	
4.4.1 voltage levels;	3.4, 8.5
4.4.2 description and quantity of assets;	8.1
4.4.3 age profiles; and	8.5
4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	8.5

Information Disclosure Requirements 2012 clause	AMP section
4.5 The asset categories discussed in clause 4.4 above should include at least the following- 4.5.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii); 4.5.2 assets owned by the EDB but installed at bulk electricity supply points owned by others; 4.5.3 **EDB** owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and 4.5.4 other generation plant owned by the **EDB**.	 8.5.1-9 8.5.10 8.5.9.2 8.5.9.2
Service Levels 5. The **AMP** must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the **AMP planning period**. The targets should reflect what is practically achievable given the current **network** configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the **AMP planning period**.	6
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**.	7.1
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.	 6.5 6.4, 8.5
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.	6, 7.1
9. Targets should be compared to historic values where available to provide context and scale to the reader.	6
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.	7
Network Development Planning 11. **AMP**s must provide a detailed description of **network** development plans, including— 11.1 A description of the planning criteria and assumptions for **network** development;	 9.1, 9.2

Information Disclosure Requirements 2012 clause	AMP section
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;	9.1, 9.2
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;	9.1.6
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;	8.2 & 9.1.6
11.4.2 the approach used to identify standard designs.	8.2 & 9.1.6
11.5 A description of strategies or processes (if any) used by the **EDB** that promote the energy efficient operation of the **network**.	9.1.7
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**.	9.1.10
11.7 A description of the process and criteria used to prioritise **network** development projects and how these processes and criteria align with the overall corporate goals and vision.	5.2
11.8 Details of demand forecasts, the basis on which they are derived, and the specific **network** locations where constraints are expected due to forecast increases in demand;	
11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	9.2.1
11.8.2 provide separate forecasts to at least the **zone substation** level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	9.4-9.6
11.8.3 identify any **network** or equipment constraints that may arise due to the anticipated growth in demand during the **AMP planning period**; and	9.4-8.6
11.8.4 discuss the impact on the load forecasts of any anticipated levels of **distributed generation** in a **network**, and the projected impact of any demand management initiatives.	9.1.9
11.9 Analysis of the significant **network** level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	
11.9.1 the reasons for choosing a selected option for projects where decisions have been made;	9.4-9.7
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;	9.4-9.7
11.9.3 consideration of planned innovations that improve efficiencies within the **network**, such as improved utilisation, extended asset lives, and deferred investment.	9.1.10

Information Disclosure Requirements 2012 clause	AMP section
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**.	9.4-9.7
11.11 A description of the **EDB**'s policies on **distributed generation**, including the policies for connecting **distributed generation**. The impact of such generation on network development plans must also be stated.	9.1.9
11.12 A description of the **EDB**'s policies on non-network solutions, including-	
11.12.1 economically feasible and practical alternatives to conventional **network** augmentation. These are typically approaches that would reduce **network** demand and/or improve asset utilisation; and	9.1.8
11.12.2 the potential for non-network solutions to address **network** problems or constraints.	9.1.8
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12. The **AMP** must provide a detailed description of the lifecycle asset management processes, including—	
12.1 The key drivers for maintenance planning and assumptions;	8.4 & 8.5
12.2 Identification of **routine and corrective maintenance and inspection** policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	
12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	8.5
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	8.5
12.2.3 budgets for maintenance activities broken down by asset category for the **AMP planning period**.	8.6

Information Disclosure Requirements 2012 clause	AMP section
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;	8.2, 8.5
12.3.2 a description of innovations made that have deferred asset replacement;	8.5
12.3.3 a description of the projects currently underway or planned for the next 12 months;	8.5
12.3.4 a summary of the projects planned for the following four years (where known); and	8.5
12.3.5 an overview of other work being considered for the remainder of the **AMP planning period**.	8.5–8.6
12.4 The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	Yes
12.5 Identification of the approach used for developing **capital expenditure** projections for lifecycle asset management. This must include an explanation of:	
12.5.1 the approach that the **EDB** uses to inform its **capital expenditure** projections for lifecycle asset management; and	8.2–8.3
12.5.2 the rationale for using the approach for each asset category.	8.3
12.6 Identification of **vegetation management** related maintenance. This must include an explanation of the approach and assumptions that the **EDB** uses to inform its **vegetation management** related maintenance.	7.4.3
12.7 The **EDB's** consideration of non-network solutions to inform its **capital and operational expenditure** projections for lifecycle asset management. This must include an explanation of the approach and assumptions the **EDB** used to inform these expenditure projections.	8.2
Non-Network Development, Maintenance and Renewal	
13. **AMP**s must provide a summary description of material non-network development, maintenance and renewal plans, including—	
13.1 a description of **non-network assets**;	11.1-11.6
13.2 development, maintenance and renewal policies that cover them;	11.1–11.4
13.3 a description of material **capital expenditure** projects (where known) planned for the next five years;	11.1.4
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	11.7

Information Disclosure Requirements 2012 clause	AMP section
14. **AMP**s must provide details of risk policies, assessment, and mitigation, including—	
14.1 Methods, details and conclusions of risk analysis;	5.7
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;	12.4
14.3 A description of the policies to mitigate or manage the risks of events identified in sub clause 14.2;	5.7.3, 12.4
14.4 Details of emergency response and contingency plans.	12.3
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;	6
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	5.6
15.4 An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the **AMP** must describe any planned initiatives to address the situation.	5.6
Capability to Deliver	
16. **AMPs** must describe the processes used by the **EDB** to ensure that-	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved;	2.5, 4.4
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	3.2
Requirements to provide qualitative information in narrative form	
17. AMPs must include qualitative information in narrative form, as prescribed in clauses 17.1-17.7 below:	
Notice of planned and unplanned interruptions	
17.1 a description of how the **EDB** provides notice to and communicates with **consumers** regarding **planned interruptions** and **unplanned interruptions**, including any changes to the **EDB's** processes and communications in respect of **planned interruptions** and **unplanned interruptions**;	6.5.3

Information Disclosure Requirements 2012 clause	AMP section
Voltage quality	
17.2 a description of the **EDB's** practices for monitoring voltage, including:	6.5.6
17.2.1 the **EDB's** practices for monitoring voltage quality on its **low voltage network**;	
17.2.2 work the **EDB** is doing on its **low voltage network** to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010;	
17.2.3 how the **EDB** responds to and reports on voltage quality issues when the **EDB** identifies them, or when they are raised by a stakeholder;	
17.2.4 how the **EDB** communicates with affected **consumers** regarding the voltage quality work it is carrying out on its **low voltage network**; and	
17.2.5 any plans for improvements to any of the practices outlined at clauses 17.2.1-17.2.4 above;	
Customer service practices	
17.3 a description of the **EDB's** customer service practices, including:	
17.3.1 the **EDB's** customer engagement protocols and customer service measures – including customer satisfaction with the **EDB's** supply of **electricity distribution services**;	6.5.1
17.3.2 the **EDB's** approach to planning and managing customer **complaint** resolution;	6.5.7
Practices for connecting new consumers and altering existing connections	
17.4 a description of the **EDB's** practices for connecting **consumers**, including:	
17.4.1 the **EDB's** approach to planning and management of-	13.1
(a) connecting new **consumers** (offtake and injection connections), and overcoming commonly encountered issues; and	
(b) alterations to existing connections (offtake and injection connections);	
17.4.2 how the **EDB** is seeking to minimise the cost to **consumers** of new or altered connections;	13.1
17.4.3 the **EDB's** approach to planning and managing communication with **consumers** about new or altered connections; and	13.1
17.4.4 commonly encountered delays and potential timeframes for different connections.	6.5.4, 6.5.5, 13.1

Information Disclosure Requirements 2012 clause	AMP section
New connections likely to have a significant impact on network operations or asset management priorities 17.5 A description of the following: 17.5.1 how the **EDB** assesses the impact that new demand, generation, or storage capacity will have on the **EDB's network**, including: (a) how the **EDB** measures the scale and impact of new demand, generation, or storage capacity; (b) how the **EDB** takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the **EDB** takes other factors into account, eg, the network location of new demand, generation, or storage capacity; and 17.5.2 how the **EDB** assesses and manages the risk to the **network** posed by uncertainty regarding new demand, generation, or storage capacity;	9.1.9, 9.2.1.1
Innovation practices 17.6 a description of the following: 17.6.1 any **innovation practices** the **EDB** has planned or undertaken since the last **AMP** or **AMP update** was publicly disclosed, including case studies and trials; 17.6.2 the **EDB's** desired outcomes of any **innovation practices**, and how they may improve outcomes for **consumers**; 17.6.3 how the **EDB** measures success and makes decisions regarding any **innovation practices**, including how the **EDB** decides whether to commence, commercially adopt, or discontinue these practices; 17.6.4 how the **EDB's** decision-making and **innovation practices** depend on the work of other companies, including other **EDBs** and providers of non-network solutions; and 17.6.5 the types of information the **EDB** uses to inform or enable any **innovation practices**, and the **EDB's** approach to seeking that information.	10.1

Appendix E Glossary of Abbreviations

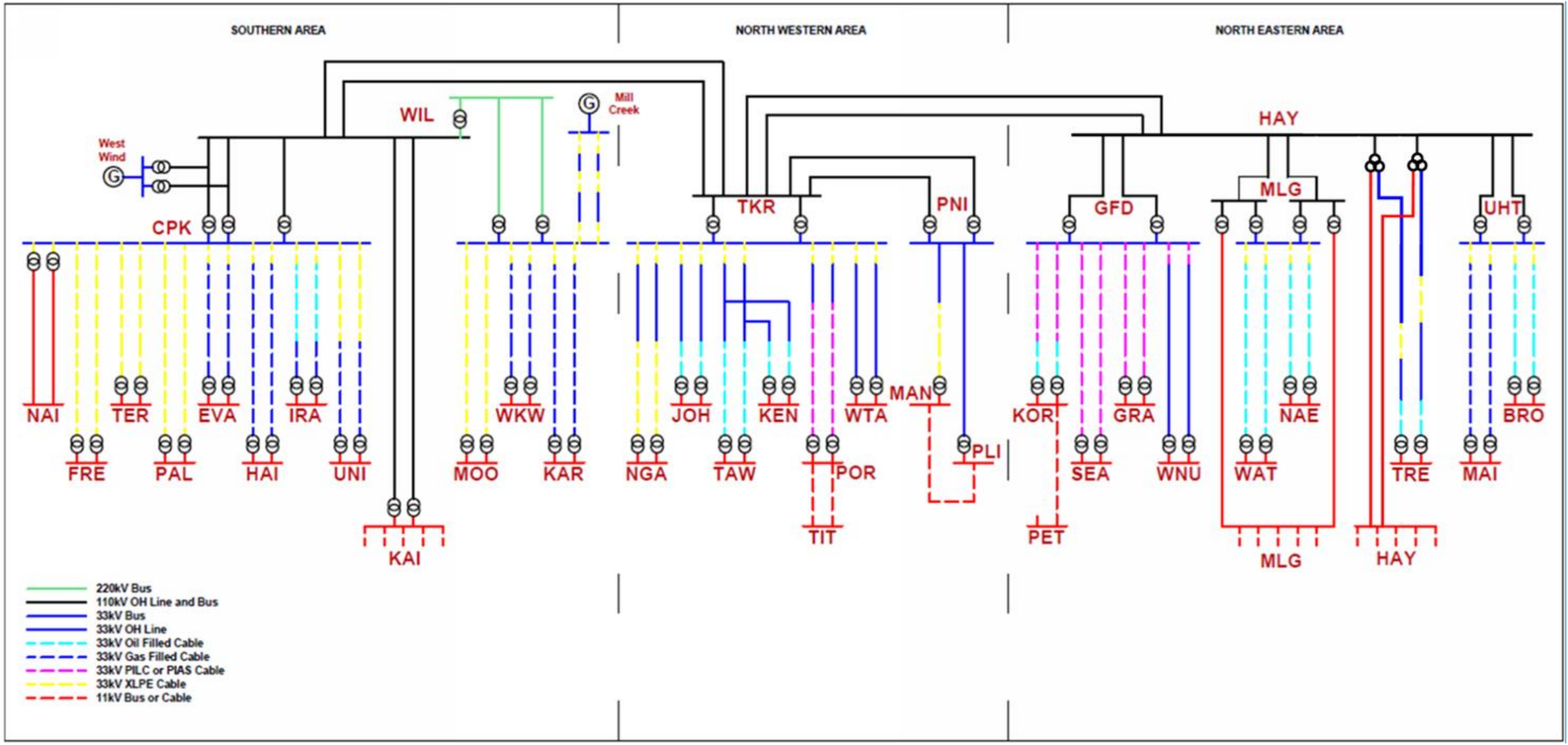
AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
ADSS	All Dielectric Self Supporting
ACI	Asset Criticality Indicator
AHI	Asset Health Indicator
AMI	Advanced Metering Infrastructure
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 Act
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
CT	Current Transformer
Cu	Copper
DC	Direct Current
DDA	Default Distributor Agreement
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
ERP	Emergency Response Plan
ETR	Estimated Time of Restoration
EV	Electric Vehicle
FDIR	Fault Detection, Isolation and Restoration
FPI	Fault Passage Indicator
FSA	Field Services Agreement
GWh	Gigawatt Hour
GIS	Geographical Information System
GXP	Grid Exit Point
HCC	Hutt City Council
HILP	High Impact Low Probability
HLR	High Level Request/Response
HSE	Health, Safety and Environmental
HSW	Health and Safety Work Act (2015)
HV	High Voltage
ICP	Installation Control Point
IEEE	Institute of Electrical and Electronic Engineers
IISC	International Infrastructure Services Company (NZ Branch)
IEP	Initial Evaluation Procedure of Seismic Assessment
IPS	Intruder Prevention System
ISO	International Standards Organisation
IoT	Internet of Things
IIoT	Industrial Internet of Things
IT	Information Technology
ITRP	Information Technology Recovery Plan
km	Kilometre
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light Emitting Diode
LEVCF	EECA's Low Emission Vehicle Contestable Fund
LTI	Lost time injury

LTIFR	Lost time injury frequency rate 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
MW	Megawatt
MWFM	Mobile Workforce Management
MVA	Megavolt Ampere
NBS	New Building Standard
NCR	Network Control Room
NDRP	Network Development and Reinforcement Plan
NIWA	National Institute of Water and Atmospheric Research
NPV	Net Present Value
OCB	Oil Circuit Breaker
OD-ID	Outdoor to Indoor conversion
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
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
SF_6	Sulphur Hexafluoride

SPS	Special Protection Scheme
TASA	Tap Changer Activity Signature Analysis
TCA	Transformer Condition Assessment
TNIFR	Total notifiable injury frequency rate 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
XLPE	Cross Linked Polyethylene insulation

Appendix F Single Line Diagram



Appendix G Director Certification

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Richard Pearson and Charles Tsai, being directors of Wellington Electricity Lines Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of Wellington Electricity Lines Limited prepared for the purposes of clause 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on the basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Wellington Electricity Lines Limited's corporate vision and strategy and are documented in retained records.

Richard Pearson	Charles Tsai
Chairman	Director
28 March 2024	28 March 2024