Asset Management Plan 2019

1 April 2019 - 31 March 2029

COUNTIES POWER

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SERVICING OVER
43,000
HOMES, FARMS & BUSINESSES

$300m
Asset Base

Plan Summary

Introduction

Counties Power's mission is to provide safe, reliable and cost effective electricity distribution to the consumers of Franklin. The purpose of the Asset Management Plan (AMP) is to ensure we manage our assets over their useful life in a smart and sustainable manner in order to provide a level of service our consumers want and for which they are willing to pay. The AMP is a vital planning tool as it focuses our decisions, investments and priorities to ensure our assets provide enduring value and are a reflection of our corporate objectives, mission and values. Investments and priorities are aligned to our long term strategic goals, the dynamic needs of our consumers and our stakeholders and the changing market and technological landscape, all of which we have invested significantly in researching in preparation for completing the AMP.

The 2019 – 2029 AMP sets out the purpose and objective of our asset management practices to assist us in managing our assets over their lifecycle in an efficient, effective and sustainable manner in order to provide a level of service that our customers want and for which they are willing to pay. This is a vital planning document as it focuses our decisions and activities so that our assets provide enduring value to our consumers, our stakeholders and ourselves.

Counties Power has been distributing a reliable and ubiquitous electricity supply to the consumers of Franklin for over 90 years. It is our intention to continue to do so for at least the foreseeable future meaning we must, as a minimum, meet our consumer and stakeholder expectations of performance. Demand-side and supply-side technology is developing rapidly and offers consumers and energy providers options for improvement, service transformation and efficiency that are unheralded in the sector. With the largest penetration of smart meters in New Zealand, a range of innovative, on-line applications for consumers and field staff along with investments in electric vehicles (EVs), EV charging stations, a battery energy storage system and solar panels, Counties Power intends to remain ahead of technology change through research, direct investment and by partnering with some of the world's most innovative and proven providers of energy and ICT solutions. We must evolve and continually improve our operations to ensure we are offering, overall, the best service we can to the very consumers who own the company and who, ultimately, have choice over how its assets are best managed.

The AMP covers the period from 1 April 2019 through to 31 March 2029 and was approved by our Board of Directors on 20 March 2019.

$70m
Revenue

180
Employees

About Counties Power

Counties Power owns, manages and operates an electricity distribution network in the southern Auckland, Waikato and Hauraki district areas with a system length of 3,200 km covering an area of approximately 2,250 km^2. The Auckland Council area covers 830 km^2 (37%) of the Counties Power network, the Waikato District covers 1,340 km^2 (60%), and the Hauraki District covers the remaining 80 km^2 (3%). We receive power from the national grid at the Bombay and Glenbrook Grid Exit Points (GXPs) and then transport it to our consumers via eight zone substations and our extensive network of overhead and underground lines, cables, transformers and other equipment.

Counties Power is 100% consumer owned. All shares are held by the Trustees of the Counties Power Consumer Trust (Trust) on behalf of all local power consumers. The Trust has a total of five Trustees, of which two are required to be elected every two years. Counties Power is managed for the benefit of its consumers and their communities. The Trust oversees the performance of Counties Power through the appointment of a Board of Directors (Board). The Board and Management of Counties Power consult the Trust on the company's strategic direction, business plans, and asset management measures and targets. Information about the Trust can be obtained from www.countiespowertrust.co.nz.

$35m
Network Investment

Our operating environment

Network

The Counties Power network has traditionally been a provincial 'town and country' network distributing electricity across a broad geography in the southern Auckland and the northern Waikato region. However, the recent and continuing growth in housing and the establishment of substantial new industrial factories is seeing this rapidly change to us being part of the greater urban Auckland area, but still with a substantial rural network.

Today, over 70% of the Counties Power network is rural overhead, however the urban networks supplying Pukekohe, Waiuku, Tuakau, Pokeno, Drury and parts of Papakura comprise a split of overhead and underground assets. Generally, the eastern part of the network is newer, higher in ICP density and subject to high levels of growth in the areas adjacent to motorway and state highway corridors. The western side of the network is older, generally more remote, and has had a lower customer and load density. It has previously been subject to little growth, but this is changing with the development of Special Housing Areas and other subdivisions in several locations.

The Counties Power network is exposed to a range of environmental conditions, including weather, particularly the harsh coastal environment around the Awhitu Peninsula, and vegetation across the entire network but most notably in the areas around the Hunua Ranges.

$11.8m
Discount for Customers

Growth

The Counties Power network is amongst the fastest growing electricity networks in New Zealand with connection growth in the order of 2 to 3% per annum. This is largely driven by the growth of Auckland and our location within the 'golden triangle' of growth between Tauranga, Hamilton and Auckland.

The population of the area grew by 11.5% between the 2006 and 2013 census periods[1]. Auckland was the fastest growing region, increasing by 8.5% over the same period. Waikato district was ranked in the top 10 territorial areas with a 10.1% population growth. The Hauraki district population decreased slightly overall, however the Kaiaua area population growth increased by 19% (an area which is supplied by Counties Power).

The largest contributor to demand growth in the medium term is expected to be industrial and residential developments around Tuakau, Pokeno, the Drury South Business Park development, and the Special Housing Areas at Hingaia, Drury and Paerata as well as residential subdivisions at Clarks Beach, Glenbrook Beach and Kingseat. However, the supply of land for housing and industrial/commercial development is an important planning issue for Auckland. Greenfield areas identified in the Auckland Plan Development Strategy, consisting of Hingaia, Opaheke, Drury, Karaka, Paerata and Pukekohe, will collectively see an additional capacity of up to 42,000 houses over the long term.

[1] At the time of writing this AMP, the most recent (2018) census data was not available.

43,000
Customers

Emerging technologies

Emerging technologies are recognised as one of the biggest issues across the electricity industry sector in the medium to long term. Embedded generation, energy storage, energy efficiency measures, demand side management initiatives and new load types such as Electric Vehicles (EVs) may result in modified load growth patterns. To date the impact of embedded generation has been minimal, as the uptake in New Zealand has been low compared to other countries. This is expected to continue unless subsidies are introduced. We anticipate that EVs have the potential to cause significant disruption to our network. Research papers have been written by others in the industry examining this issue. We believe that the ability to control the impact of chargers (either through load control or through pricing structures) would encourage EVs to be charged at off peak times, allowing for connection to the network without the need for significant network investment.

Counties Power continues to keep a watching brief on demand side technologies and options, along with other new supply side technology and where appropriate undertake or participate in trials to understand how these options could impact on our business. We are trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of the investment planning process.

Local Authorities and District Plans

The Counties Power network operates in an area split between three different territorial authorities; Auckland Council (37% of the Counties Power area), Waikato District Council (60%) and the balance in the Hauraki District Council area. Each territorial authority produces its own planning documents with rules which give effect to the Resource Management Act 1991, to promote the sustainable management of natural and physical resources.

Within the area of Counties Power that is administered by Auckland Council, the Auckland Plan 2050 will guide the long term spatial development of the wider Auckland area over the next 30 years. Its aims and objectives are supported by a number of documents including the Future Urban Land Supply Strategy 2017 (FULSS) and the Auckland Unitary Plan Operative in Part (AUP(OP)). The FULSS provides a long term, proactive approach to the delivery and timing of development ready land, providing clarity and certainty upon which to base infrastructure planning and investment decisions. The FULSS has recently been updated to reflect changes brought about by the Special Housing Areas, the AUP(OP) and new demand for development.   The AUP(OP) came into effect in 2016 and replaced the former Regional Policy Statements and 12 District and Regional Plans. While there are still a number of outstanding appeals to the plan, (some of which are based in the Counties Power area), which means that it cannot be notified as being fully operative, Counties Power must be mindful of the requirements of the AUP(OP) in the design, construction and maintenance of its network. While these requirements have the potential to add cost and complexity to the maintenance and future development of the network, our experience to date has been that these circumstances occur only rarely.

In the southern part of the Counties Power area the rules of the Waikato Regional Plan determine how we undertake work which might impact on the use, development or protection of natural resources; while the district plan rules are provided by the Proposed Waikato District Plan. Stage 1 of the Proposed Waikato District Plan, which was publicly notified in July 2018, combines the Franklin and Waikato sections into a single plan for the Waikato district. The Proposed Waikato District Plan will provide guidance and set the rules that will shape growth and development in the southern part of the Counties Power area for the next 10 years. Submissions on Stage 1 of the proposed plan closed in early October 2018, with further submissions likely to be provided by Counties Power in due course.

In the Hauraki District Council area, the requirements for Counties Power's operation, maintenance and development of the network are still based upon the Franklin District Plan. There are currently no proposals to review the Hauraki or Franklin section to create a single plan with district wide rules.

Regulation

Counties Power, as an electricity distribution business, is subject to regulation by the Commerce Commission, under Part 4 of the *Commerce Act 1986*. Due to the ownership structure, it is exempt from the Default Price - Quality Regime, as the consumers are the beneficial owners through the Counties Power Consumer Trust, however it is still required to comply with the Information Disclosure Requirements, of which the production of an annual 10 year AMP is one requirement.

The business is also regulated by the Electricity Authority and is subject to compliance with the *Electricity Industry Participation Code*, both as a distributor and also as a metering equipment provider.

Regulatory changes imposed by the Electricity Authority on other industry participants, such as Transpower, can have a consequential effect on the business, such as the method for determining transmission pricing.

In addition to economic and industry regulation, Counties Power has a range of legislative requirements to meet including the *Electricity Act 1992*, the *Electricity (Safety) Regulations 2010*, *Health and Safety at Work Act 2015* and the *Electricity (Hazards from Trees) Regulations 2003*, amongst others.

Consumer value and cost reflective pricing

Counties Power's capital and operating expenditure is continuing to grow as its network expands at a time when peak demand is growing twice as fast as sales volume and where average usage per consumer is decreasing. The combination of Counties Power's current volume based pricing, and the fact it chose not to increase its distribution prices to its consumers for the past 5 years between 2015 and 2019 in an endeavour to improve consumer value, means that distribution revenue per consumer is also decreasing.

As with any electricity lines company, however, most of the company's costs of providing distribution network access are fixed and are associated with building and maintaining infrastructure that can meet peak demand. The variable cost component is driven by the consumer's winter peak demand requiring additional distribution capacity and associated transmission charges. Because consumer volume is increasing at a lower rate than the consumer peak demand is increasing, this is creating a mismatch between revenue received and costs incurred. Counties Power's current lines charges to its consumers are not directly cost-reflective. Counties Power are currently consulting with retailers in order to establish a roadmap that will introduce pricing that is more cost reflective but which will have minimal cost impact on the consumers on our network.

The Company believes that moving to a more cost reflective structure will enable consumer choice and control and ensure fairer pricing to all consumers. For these reasons, the Electricity Authority has also instructed all lines companies to introduce cost reflective pricing as a payment option. To do this Counties Power introduced prices that are higher at peak times and lower off-peak. This then sends clear price signals to consumers to reduce their peak time use and save money and reduce costs to Counties Power. It also gives the choice to customers that if they use power during peak times they still can, but they have to pay more to cover the higher costs to Counties Power.

As a consequence, in 2014 Counties Power introduced smart tariffs that provided peak, off-peak and shoulder pricing options for residential and business customers. No retailers opted to use this tariff, and so on 1 April 2016 Counties Power aligned the tariff to Vector's mass market peak and off-peak tariff to encourage retailer uptake. To date, only two retailers have opted to use the tariff, but this is expected to change in the future as the industry as a whole moves to cost reflective pricing.

Stakeholders

Stakeholder requirements are important to us and we place considerable focus on identifying and meeting stakeholder expectations. As we have a wide range of stakeholders, it is important that conflicting stakeholder requirements are managed appropriately and consistently.

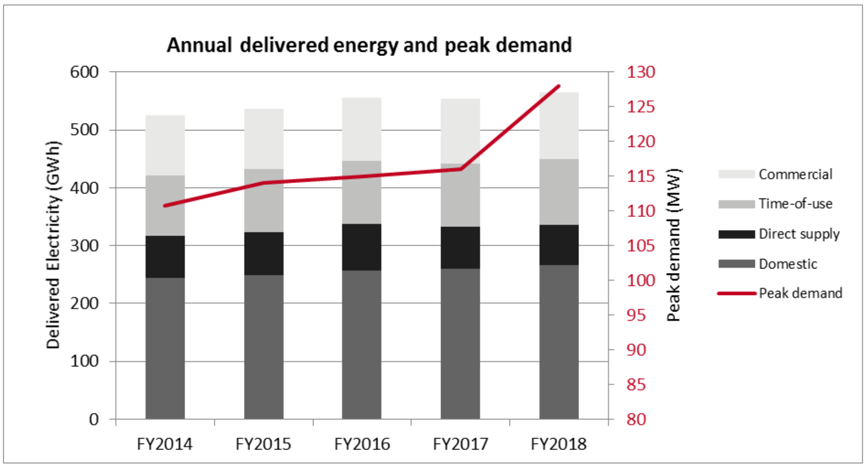
Our stakeholders include consumers, the community and landowners, local authorities, electricity retailers, regulators and government agencies, Transpower, our Board, our employees, our contractors, our suppliers and the Counties Power Consumer Trust.


100%
CONSUMER OWNED

Our consumers

Our consumers are our owners. As at October 2018, there were 42,525 ICPs connected to the Counties Power network with a peak demand of approximately 116MW and annual delivered energy of 563 GWh in the year ending 31 March 2018. In the most recent winter peaks in 2018, peak demand reached 128MW. The network load profile is winter peaking, with residential loads showing typical morning and evening peaks, and commercial loads generally having a constant daytime load.

Demand on the network is increasing daily with new residential, commercial and industrial customers being connected. This is changing the customer mix from a predominantly rural, small town and rural commercial and industrial base (e.g. quarries, mines, food production) to an urban residential and industrial mix.

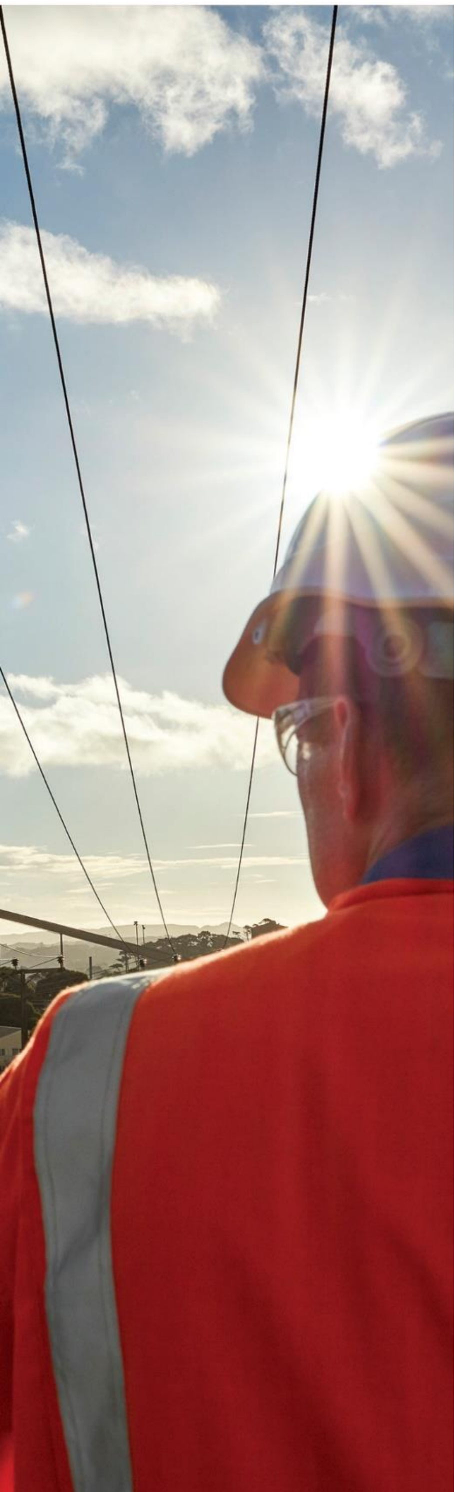


Energy volumes and network demand 2014 to 2018

A breakdown of the ICP type is shown in the table below:

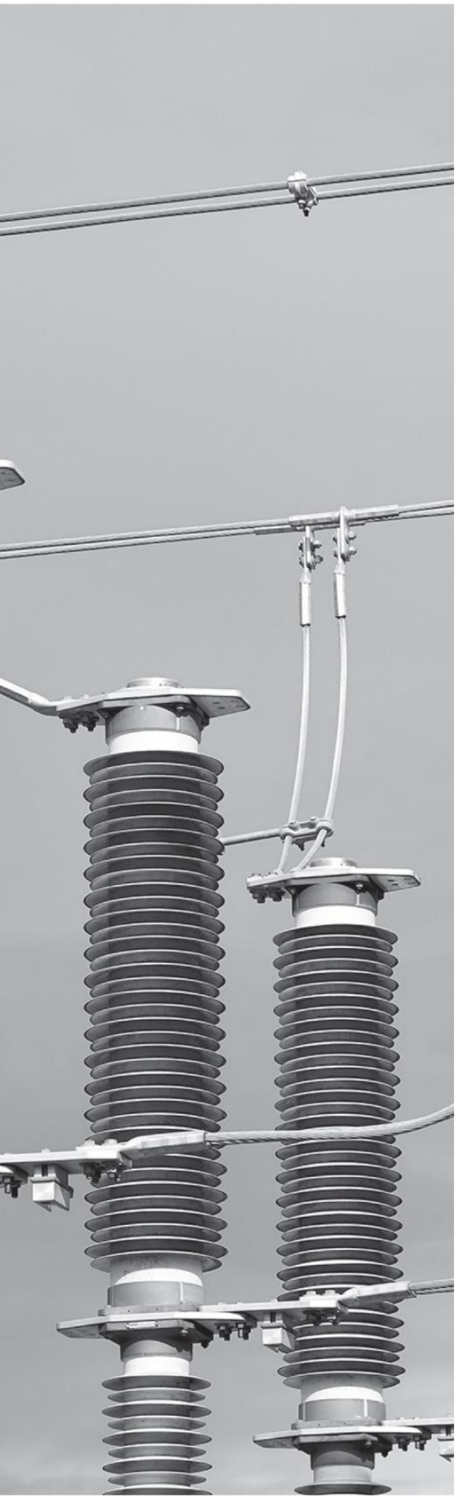
	ICPs	Delivered GWh*
Direct supply	7	69.6
Time-of-use	166	113.7
Commercial	7,146	114.3
Domestic	35,206	265.6
Total	**42,525**	**563.2**

* Delivered GWh in FY2017/18.



Our major customers are in a range of industry sectors including steel production, waste product and material handling, food and beverage producers, as well as timber and construction material processing operations. We also supply civic amenities such as streetlights, pumping stations, schools, libraries and emergency service providers. All have differing requirements of their electricity supply which need to be considered.

Counties Power has eight embedded generators greater than 10kW and 632 embedded generators under 10kW. The eight large embedded generators consist of hydro, solar and landfill gas, with the smaller generators being predominantly solar PV installations.



Our network

Counties Power has two points of supply from Transpower's National Grid via Grid Exit Points (GXPs) at Glenbrook and Bombay. The Glenbrook GXP supplies our western substations at 33kV whilst the Bombay GXP supplies the eastern substations at 110kV and 33kV. 73% of ICPs are supplied from the Bombay GXP at 110kV and 33kV, and the remaining 27% from the Glenbrook GXP.

Our subtransmission network consists of a network of 110kV and 33kV subtransmission lines from Bombay and Glenbrook GXPs. The architecture of the network is typically radial subtransmission circuits connecting to 33kV buses or configured as transformer-feeders where no bus is installed. Our 110kV supply to Pukekohe and Tuakau is operated as a ring with three circuits supplying the two zone substations.

Three zone substations (Pukekohe, Opaheke and Tuakau) operate at 110kV with distribution supply operating at 22kV. The remaining five zone substations (Mangatawhiri, Ramarama, Waiuku, Karaka and Maioro) are supplied via the 33kV subtransmission network with distribution supply operating at 11kV, with some feeders stepped up to 22kV.

Our zone substations supply a total of 53 distribution feeders (operating at 22kV or 11kV) via approximately 4,043 distribution substations (including private substations). The distribution substations connect over 42,525 consumers to the Counties Power network.

Distribution substations have pad mount or pole mount transformers which transform the 22kV or 11kV distribution voltage to 400V/230V reticulation voltage.

A summary of all our network assets is provided in Section 2.7 of this Asset Management Plan.

Our service levels

Our service levels help link the company vision to the expectations of consumers and to assist us in measuring and improving performance. In particular, they inform our asset management practices by having safety as our top priority.

Customer surveys

Counties Power conducts customer surveys at least once every two years and post-service feedback surveys every month. These customer surveys measure and monitor both residential and commercial customers experience and rating of the power supply service they receive.

Service levels – workplace safety

Our health and safety vision is “no harm for our people, our communities and the environments in which we operate”.

To achieve our health and safety vision, and our corporate mission and values, we have placed health and safety as the highest priority over all our business objectives. We believe that our most important priority is the health and safety of our staff, our contractors, and visitors to our sites and the general public who interact with our assets. To this end, we will always conduct ourselves in a manner that protects the health and safety of our employees and contractors (Counties Power Team Members) visitors to our sites and members of the public who interact with us and our assets.

We acknowledge our responsibilities for maintaining high health and safety standards in the work place and will provide competent resources and effective systems and sufficient capacity within our business to fulfil this commitment. All Counties Power employees are required to adhere to this vision.

Service levels – public safety

Our objective is to ensure that no member of the public is harmed by our network assets, and that hazards introduced by our network assets are controlled so as to not pose a risk to the public.

In order to provide the highest levels of public safety, we have the following initiatives in place:

- Ensuring assets are operated, inspected, maintained and defects are repaired promptly in accordance with good industry practice;
- That equipment is designed, selected and installed in a way to promote public safety (safety by design);
- That earthing and protection systems are designed, tested and operate to clear faults quickly to protect members of the public from electric shock;
- Maintain compliance and certification to the requirements of NZS7901 for Public Safety Management Systems, including undertaking periodic external performance assessment;
- Public safety awareness – undertake radio and print media awareness campaigns, as well as providing safety resources on our website www.countiespower.com; and
- Active engagement with Energy Safety in relation to unsafe activity around our network by third parties, or where people have come to harm from our assets, or their own premises.

Service levels – reliability

Our objective is to operate the network to provide a level of performance that meets the expectations of consumers and customers for reliability and value for money, this includes:

- Minimising the number and duration of outages experienced by consumers;
- Restoring power as quickly and safely as possible following an unplanned outage and providing communication to keep consumers informed; and
- Providing consumers with sufficient notice ahead of planned outages required for maintenance.

There are some consumer groups on our network who demand higher levels of reliability, and are prepared to pay more for that benefit, and we accommodate their needs where practicable.

Consumer reliability service levels

We set reliability service levels for our consumers in the Use of System Agreements we have with retailers trading on our network. These outline the target times for restoration of supply following a fault on the network, as well as the timeframes for notifying the consumer that we have to turn their power supply off for planned works.

Description	Target
Restoring electricity supply after the Distributor becomes aware of the fault	Rural – 6 hours Urban – 4 hours
Notice of pre-planned supply interruption	Not less than 5 days' notice to the electricity retailer unless already agreed with by the Customer

Overall network performance

We measure overall network performance using industry standard metrics of SAIDI and SAIFI, which measure the average duration and frequency of interruptions experienced by a consumer on the Counties Power Network. We also measure the number of faults per 100km of circuit length.

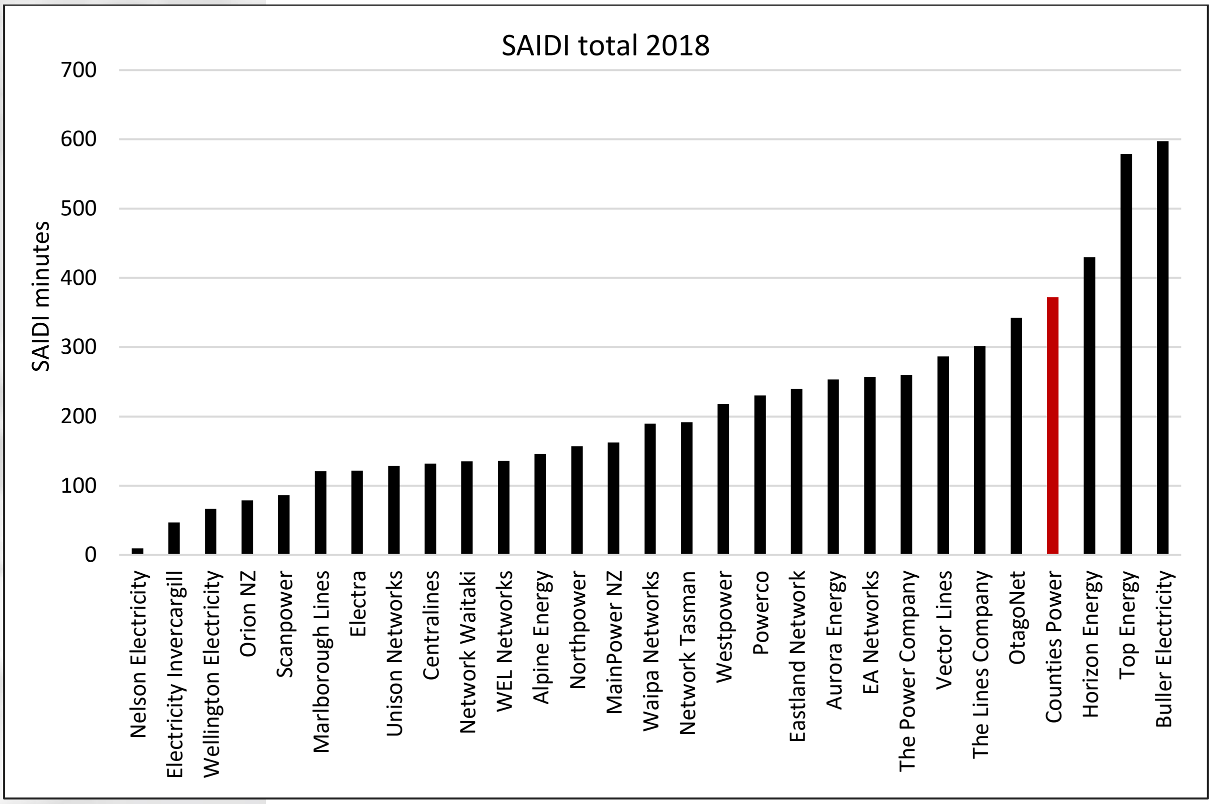
Our SAIDI and SAIFI performance and target figures are shown in the table below, normalised in accordance with the DPP method, and with industry[2] comparisons in the graphs below, normalised using the Information Disclosure method.

Network SAIDI[3]	2016	2017	2018	2019	2020	2021+ Target[4]
Counties Power	118.3	236.6	270.9	205	200	200
Industry Average	162.9	194.8	216.4			

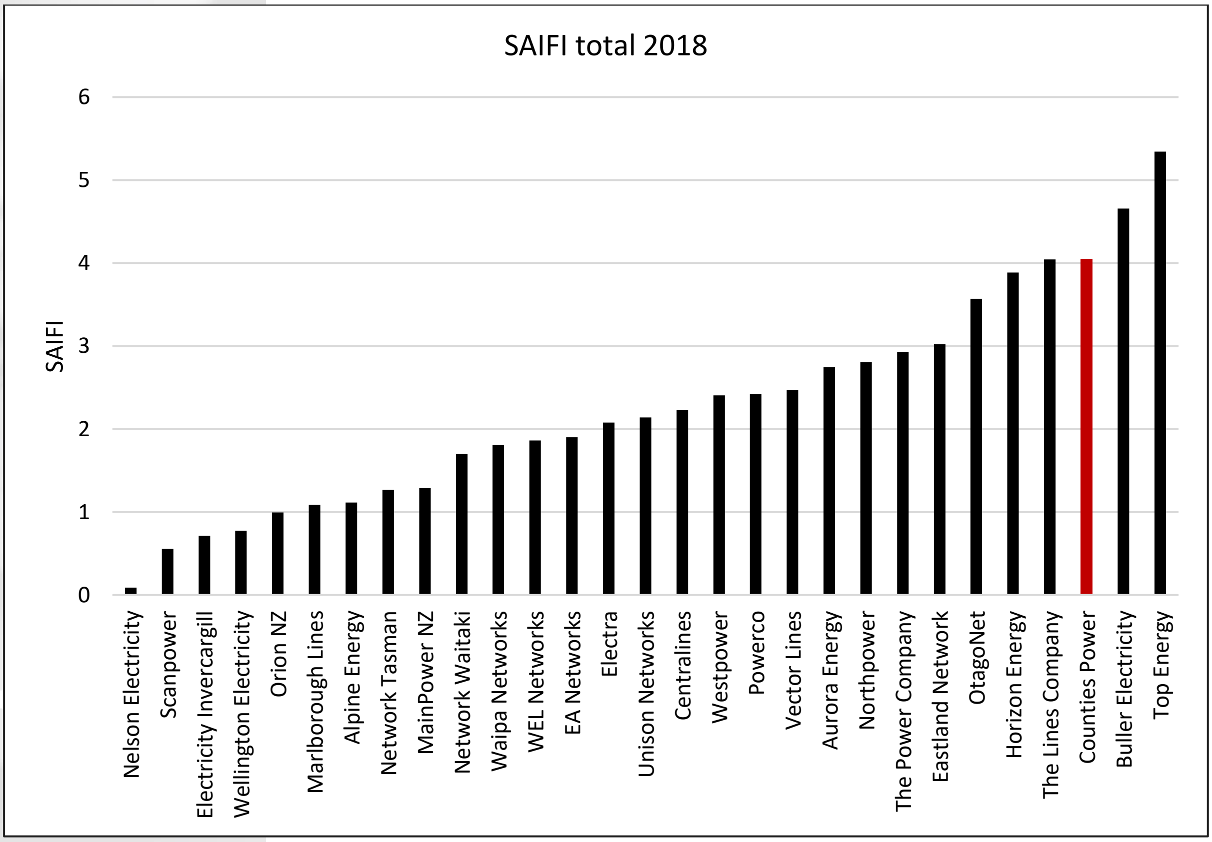
Network SAIFI[5]	2016	2017	2018	2019	2020	2021+ Target
Counties Power	2.70	3.28	3.34	2.90	2.80	2.80
Industry Average	1.88	2.07	2.27			

Faults per 100km	2016	2017	2018	2019	2020	2021+ Target
Counties Power	18.41	18.51	23.32	14.50	14.50	14.50
Industry Average	28.23	24.45	31.59			

[2] Industry SAIDI and SAIFI figures are normalised figures using the Commerce Commission ID methodology.
[3] Network SAIDI figures from 2015 onwards are normalised figures using the Commerce Commission DPP methodology
[4] Total SAIDI targets will reduce from 2020 onwards in line with the reliability investments that have been and will be made and the forecast benefits they will provide. The future level of reliability investment and expected performance benefits will be assessed in the coming year.
[5] Network SAIFI figures from 2015 onwards are normalised figures using the Commerce Commission DPP methodology



Network SAIDI – Industry Comparison 2018



Network SAIFI – Industry Comparison 2018

Network performance, as measured by SAIDI and SAIFI, is unfavourable both to our own targets, and when compared to industry averages. SAIDI and SAIFI are high relative to similar networks and reflect the higher feeder customer density numbers resulting from our extensive number of long 22kV feeders and notable increases in overhead equipment failure, debris, vehicle damage and 'no fault found' incidents which are detailed in Section 3 of this AMP.

In order to provide appropriate levels of network performance, we have put in place the following initiatives:

- Vegetation management – a proactive programme of vegetation surveys and tree trimming and removal to ensure supply is not interrupted by trees coming into contact with overhead lines;
- A focus on worst performing feeders – identifying which feeders have the greatest number of outages, as well as those that have high SAIDI and SAIFI impacts, and undertaking proactive corrective remedial works to ensure the assets on these feeders perform as expected;
- Updated security criteria for the target number of customer connections per feeder to reduce the impact of faults, including investments to split feeders with high customer numbers – as detailed in Section 6;
- Post fault analysis of all events that cause more than 20,000 customer-minutes to be lost, or affect a major customer, to identify the root cause of the fault and to implement corrective actions to prevent reoccurrence;
- Car vs pole post incident investigation and reporting, and follow up actions with internal and external stakeholders such as Police and local roading authorities;
- Increased maintenance and replacement of overhead components in worst performing areas – as detailed in Section 5; and
- Investigating new tools and technology to identify fault locations to enable quicker restoration of consumers in affected sections of the network.

Look up for power lines

Free safety disconnections

Our approach to Asset Management

Risk Management

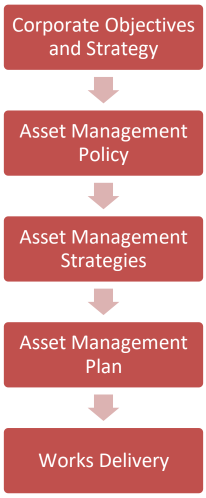
Risk management and asset management are intricately linked. We recognise that risk management is an integral part of good management practice, corporate governance, and it is central to effective asset stewardship. Our risk management framework is aligned to the *ISO 31000:2009 Risk Management – Principles and Guidelines* standard and it ensures that all our risks are identified, understood and managed consistently across all aspects of our business. Our risk management framework strengthens our asset management decision making and practices.

Public Safety Management System

Public safety is a critical component of our risk management framework. We adopt the requirements set out in NZS 7901:2008 *Electricity and Gas Industries – Safety Management Systems for Public Safety* to safeguard the public or their property from safety-related risks arising from the presence or operation of our network distribution assets.

Asset Management framework

We have developed a high level Asset Management framework for Counties Power, which provides the linkage of our corporate objectives to our asset management activities, as shown below.



Asset Management framework

Our Asset Management Policy links our Asset Management approach to our corporate objectives and details the Objectives, the Accountabilities and the Implementation considerations.

Our Asset Management Policy Objective is to “optimise the whole of life costs and the performance of the network to sustainably deliver a safe, reliable and cost effective supply to our consumers”.

We have developed asset management strategies to deliver the requirements of the Asset Management Policy, including maintenance, replacement and network development.

Maintenance strategies

Maintenance comprises asset inspection, measurement, recording and assessment of condition and undertaking required corrective or preventative actions to minimise risk and/or maximise performance. Our maintenance programme also includes reactive (fault) maintenance and vegetation management.

Replacement strategies

As we are a rapidly growing network, large parts of the network around growth areas have been rebuilt over the past 20 years, and the eastern part of our network is relatively new compared to many other networks. However the western and southern parts of the network will require significant replacement in the planning period as they have not yet benefited from growth related renewals.

Many of our major substation assets are approaching the end of their economic service life just as capacity and security constraints are becoming binding. This allows these assets to be replaced at the optimal time to maximise their service life by moving towards condition based replacement criteria and be upgraded to meet new capacity requirements at the time they are required.

Distribution assets are generally in the public domain and can present a risk to public safety. We inspect these assets at regular intervals to identify defects and undertake a condition assessment to forecast when replacement will be required. Our objective is to replace these assets based on condition before they fail or present an unacceptable risk.

Network development strategies

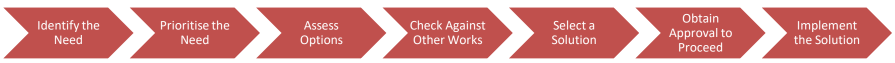
As demand on our network grows we have to ensure it is able to meet our consumer's requirements for capacity, security and reliability.

We have developed security and planning criteria and assess the network against these for the reasonable growth forecast. This results in the identification of constraints and timeframes for investment. Our strategy is to ensure that the development options we select do not lead to over investment (too much), premature investment (too soon), or lead to a high risk of asset stranding. We also aim to get as much renewal benefit as possible when upgrading or replacing assets due to growth and avoid the early write-off of assets before the end of their economic service life.

As well as projects to address capacity and security constraints, future projects include specific works focussed towards improvement of our network performance as defined by SAIDI and SAIFI.

Investment planning process

Our network investment planning process consists of a sequence of decision making steps, used to ensure we make the correct investment decisions and have adequately considered all available alternatives. A high level overview of this process is shown below.

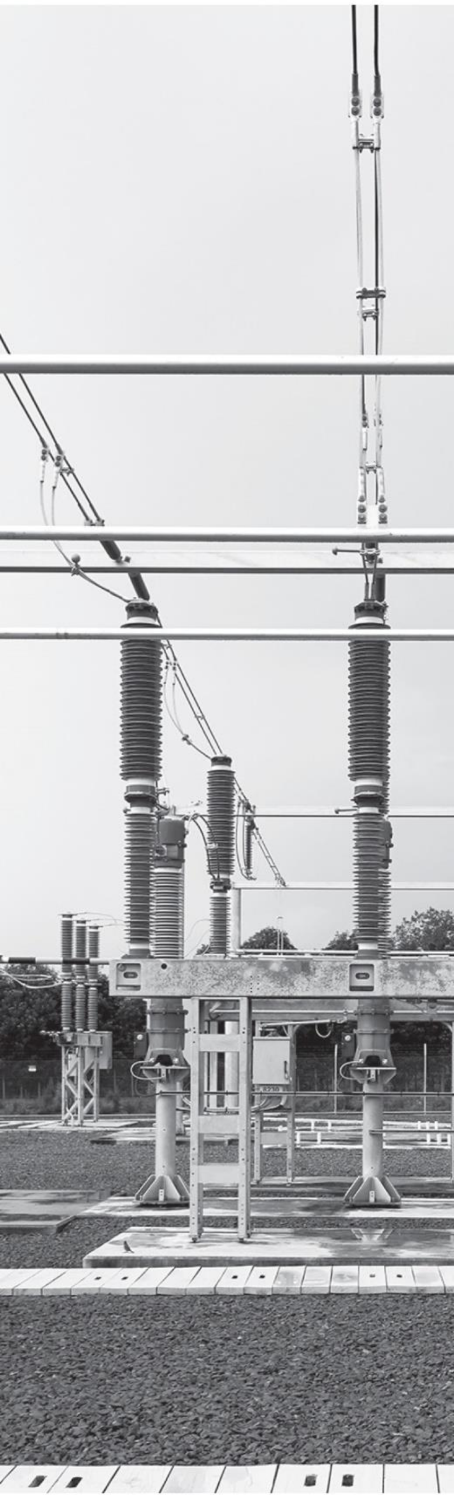


Investment planning process overview

When considering options for managing network risks and constraints, typically addressed by the construction or replacement of network assets, we also consider 'Network Alternatives' such as demand side management, distributed generation, and energy storage – an emerging area which is becoming more economic.

Asset Management systems

There are a number of key systems used in the asset management process, as well as part of our wider business operation – including our ERP system Microsoft Dynamics NAV, our GE iFix SCADA system and GE Smallworld, our GIS tool. Supporting this are specialist packages such as DIgSILENT Powerfactory, AutoCAD and our suite of field computing tools used to capture field activity data.



Asset Lifecycle planning

Major capital projects and programmes of work arising from asset lifecycle planning strategies are summarised below by asset category. These are in addition to routine inspection and maintenance programmes (operational expenditure). Full details are covered in Section 5 of this AMP.

Subtransmission

- Refurbishment of the Maioro 33kV line towards the end of the planning period (2025/26), with an estimated cost of $900,000 (dependent upon the future of the site).

Zone Substations

- Renewal of the 33kV circuit breakers at the Waiuku substation and the 11kV switchboards at the Waiuku, Maioro and Mangatawhiri substations due to age and condition. Under this plan, these will be assessed as renewal and network development projects;
- Replacement of the 22kV switchboard at the Opaheke substation in 2022/23 with an estimated cost of $2 million due to condition and capacity constraints. Under this plan, this will be assessed as a network development project;
- Replacement of the 11kV switchboard at the Maioro substation around 2024/25 with an estimated cost of $350,000 due to condition (dependent on the future of the site); and
- A continuation of the rebuild of the Waiuku substation into 2019/20 with an estimated cost of $5.7 million due to condition and seismic risk, but also to address capacity constraints. This work will also include the 33kV and 11kV circuit breakers noted above and has been assessed as a network development project.

Distribution Overhead Lines

- Replacement of small diameter copper conductors ($16mm^2$, $25mm^2$) over the planning period, continuing in higher risk areas, with an estimated programme cost of $23.0 million;
- Replacement of Swan ACSR conductor over the planning period, commencing in higher risk areas, with an estimated programme cost of $26.0 million;
- Replacement of high voltage and urban low voltage overhead networks following condition assessment, commencing high voltage network replacement projects in Mangatawhiri and Waiuku and continuing low voltage network replacement projects in Pukekohe and Waiuku with an estimated programme cost of $6.7 million; and
- Replacement of poles following inspection, focussing on hardwood, softwood and iron rail poles, and provision for additional replacement needs arising from over 2,200 poles identified in the 2017 survey and the change in policy relating to private HV line ownership from January 2018. An annual allocation of $3.35 million has been made in 2019/20, decreasing to $3.3 million from 2021/22 onwards.

Distribution Cables and Underground

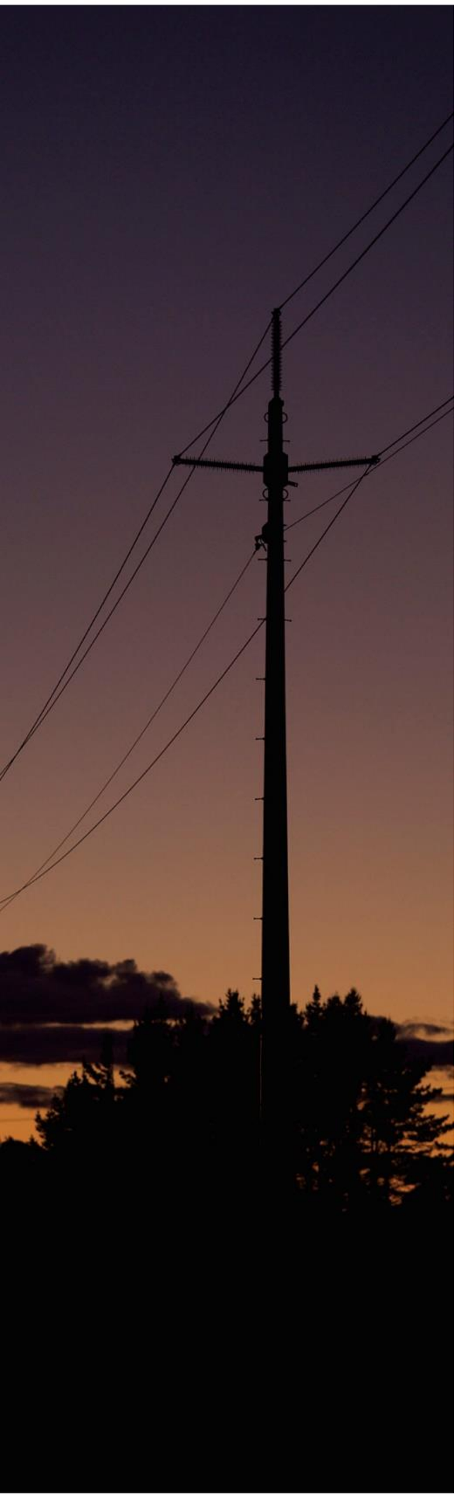
- An ongoing condition based replacement programme for distribution cables, with an average annual allocation of $200,000; and
- An ongoing condition based replacement programme for LV distribution pillars and pits, with an average annual allocation of $220,000.

Distribution Substations and Transformers

- An ongoing condition based replacement programme for distribution transformers, with an average annual allocation of $570,000 in conjunction with replacement of Andelec and Hazemeyer Ring Main Units.

Distribution Switchgear

- Replacement of Andelec and Hazemeyer Ring Main Units over a period of 5 years, with a programme budget of $1.8 million over the planning period; and
- Replacement of Air Break Switches and remote control units, with a programme budget of $5 million over the planning period.



SCADA and Communications Equipment

- Radio communication and control renewal, with an annual allowance of $50,000;
- Field Remote Terminal Unit (RTU) replacement programme - completed in line with the distribution switchgear replacement programme with an average annual allocation of $30,000; and
- SCADA Advanced Distribution Management System (ADMS) upgrade in 2020/21 with an estimated cost of $1.5 million.

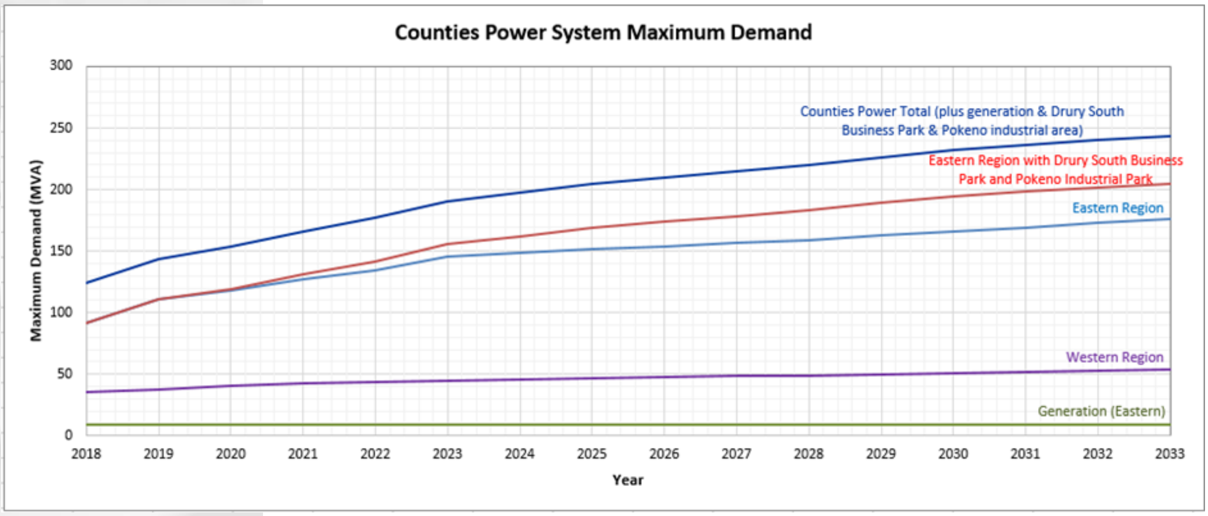
Protection, Load Control, Auxiliary Battery and Other Equipment

- Replacement of under-frequency relays at various sites in 2020/21 with an estimated cost of $300,000;
- Replacement of feeder protection relays at Karaka substation in 2019/20 with an estimated cost of $320,000;
- Replacement of feeder protection relays at Maioro in 2024/25 with an estimated cost of $240,000 (depending on the major customer's future requirements for capacity supplied from the site);
- Replacement of the Glen Murray Voltage Regulator in 2019/20 with an estimated cost of $360,000;
- Replacement of load control equipment at Glenbrook in 2019/20 with an estimated cost of $300,000 and at Opaheke in 2026/27 with an estimated cost of $200,000;
- Replacing all network locks to provide improved safety and security in 2019/20 with an estimated cost of $420,000; and
- Replacement of the batteries at substations and communication sites for which an average annual allocation of $30,000.

Network development planning

Demand forecast

The maximum demand on our system is the main driver for investing in our network. Our demand forecast defines future network requirements and is a key input into determining the appropriate timing for capacity and security related investment in our subtransmission and distribution networks over the AMP period.



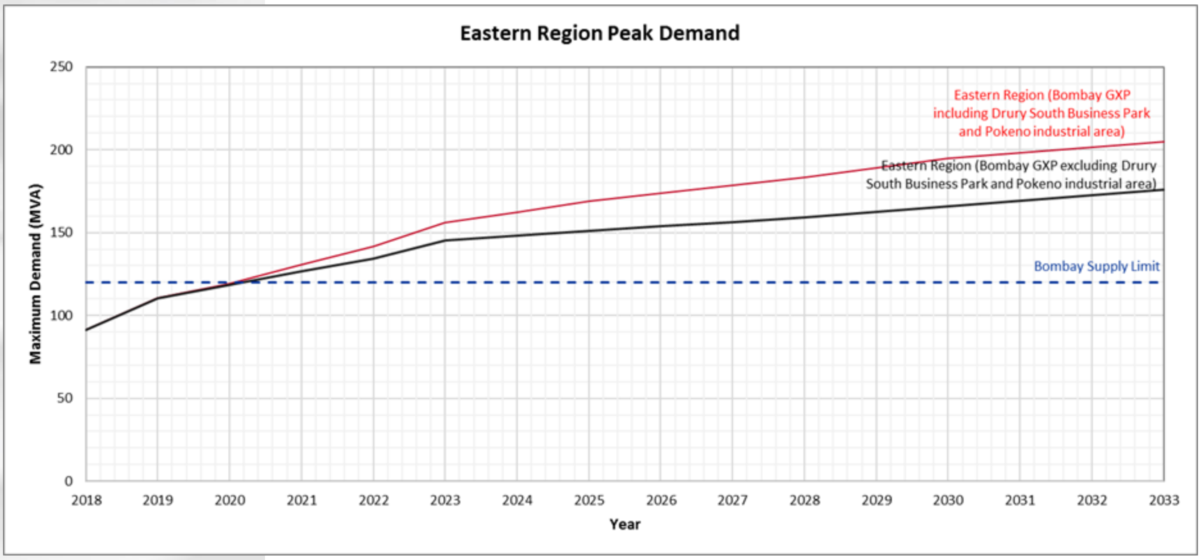
Winter Maximum Network demand

Of particular note, Auckland Council's Future Urban Land Supply Strategy 2017 (FULSS) is expected to result in a significant increase in demand on our network over the next 30 years. We have included the potential impact of Auckland Council's draft plan and any other known development in our area when developing our network development plan. Although we have treated the Drury South Business Park development separately given its potential magnitude and sensitivity to assumptions regarding reticulation timeframes and the nature of the load.

Eastern Region Development Plans

The Eastern Region is supplied from the Bombay GXP and covers areas supplied by our Opaheke, Pukekohe, Tuakau, Mangatawhiri and Ramarama Zone Substations.

The figure below shows the peak demand forecast for the Eastern Region.



Maximum Demand – Eastern Region

We currently have four proposed development programmes within the Eastern Region:

- Drury South Business Park (refer to section 6.4.2 of this AMP): Relocate a section of the Bombay to Opaheke 110kV East line, develop our network to supply the proposed Drury South Business Park by building a new 110kV Drury South Area Substation and feeders and reconfigure our network to supply the proposed new development and surrounding area. This is expected to occur in early 2019 for the line relocation, and 2020/21 for the substation and feeder projects at an estimated cost in the order of $20.5 million. Connection to the proposed Transpower Drury GXP is expected in 2022/23 at a cost of $2 million;

- Pokeno Industrial Area and residential developments (refer to section 6.4.3 of this AMP): Establish a new Zone Substation at Pokeno connected to the Bombay to Tuakau 110kV line with two new 40MVA 110/22kV transformers, new 22kV switchgear and associated buildings and auxiliary equipment at an estimated cost of $16.0m. As land and some equipment procurement occurred in FY19, the future investment is estimated at $12.7m;
- Eastern Supply Project (refer to Section 6.4.7 of the 2019 Asset Management Plan): further development our network area currently supplied by the Mangatawhiri and Ramarama substations. This project will coincide with Transpower's "end of life" decommissioning of their 110/33kV transformers and associated 33kV switchgear at Bombay GXP and is expected to occur in 2021/22 for an estimated cost in the order of $12.7 million. The development work includes:
  - converting our subtransmission network in the area to 110kV;
  - building a new 110kV Bombay Area Zone Substation adjacent to the Bombay GXP to replace the Mangatawhiri and Ramarama substations; and
- Pukekohe North (Paerata Rise and Karaka North). Major housing developments are planned for both of these areas, and Paerata Rise (formerly Wesley College) will include a town centre and railway station. An increase in load of 20MW from these two developments is expected over the planning period. The proposed solution in this area is to establish a new zone substation, supplied at 110kV from Drury in the 2024/26 period at an estimated cost of $25 million.

In addition to these large scale developments, there are major projects identified within the planning period at the following locations:

Opaheke

Our development plan for the Opaheke Zone Substation feeders is to:

- Convert the Papakura South feeder to 22kV operation in 2019/20, at an estimated cost of $400,000, to be carried out in conjunction with condition based replacement of distribution switchgear on the feeder;
- Upgrade the Bremner Road to Norrie Road section of the Drury feeder in 2019/20 at an estimated cost of $300,000 to increase backfeed capacity to the Anchor Factory feeder;
- Install earthing transformers at the Opaheke substation for improvement of power quality in 2019/20, at an estimated cost of $550,000;
- Upgrade the Hingaia Road section of the Hingaia feeder in 2021/22 at an estimated cost of $400,000 to increase backfeed capacity to Anchor Factory feeder;
- Replace the 22kV switchboard at the Opaheke Substation in 2022/23, with an estimated cost of $2 million to increase backfeed capacity to the Beach Rd, Drury and Hingaia feeders. The primary driver for this project is the need for more feeder bays, but it will also address the known condition issue associated with the switchboard;
- Create a new feeder to reduce customer numbers on the Beach Rd feeder in 2023/24 at a cost of $1.25 million;
- Create a new feeder to reduce customer numbers on the Red Hill feeder and improve network performance in 2023/24 at a cost of $1.8 million;
- Create a link between the Beach Rd and Hingaia feeders to improve backfeed options in 2023/24 at a cost of $200,000; and
- Rebuild a section of the Drury Hills feeder to improve network performance in 2023/24 at an estimated cost of $880,000.

Pukekohe

Our development plan for the Pukekohe Zone Substation feeders is to:

- Install a recloser on the Railway feeder to improve supply reliability in 2019/20, at an estimated cost of $35,000;
- Upgrade sections of the Anchor Factory and Pukekohe East feeders to transfer industrial load from the Anchor Factory to Pukekohe East in 2019/20, at an estimated cost of $460,000;
- Install earthing transformers at the Pukekohe substation for improvement of power quality in 2019/20, at an estimated cost of $550,000;
- Utilise existing sectionalisers and upgrade conductors on urban feeders to transfer high density residential load from rural feeder sections in 2020/21, at an estimated cost of $50,000;
- Upgrade 300kVA autotransformers to 750kVA on the Anchor Factory feeder to address rating constraints in 2022/23, at an estimated cost of $130,000;
- Install a new 22kV feeder section and ring main unit to split the front end of the Cape Hill feeder in 2023/24, at an estimated cost of $750,000;
- Underground a section of the Pukekohe Hill feeder along Kitchener Road to improve reliability in 2023/24, at an estimated cost of $300,000;
- Rebuild a section of the Pukekohe Town feeder along Tobin Street as an underground section to improve reliability in 2023/24, at an estimated cost of $500,000;
- Install a new 22kV feeder section and ring main unit to split the front end of the Pukekohe West feeder in 2023/24, at an estimated cost of $800,000; and
- Upgrade 700m of copper and 350m of swan conductor section of the Anchor Factory feeder to backfeed the Pukekohe Hill feeder in 2024/25, at an estimated cost of $280,000.

Tuakau and Pokeno

Our development plan for the Tuakau Zone Substation feeders is to:

- Complete the establishment of the Pukekawa Trunk feeder to the Pukekawa switching station in 2019/20, at an estimated cost of $690,000;
- Upgrade auto-transformers and install voltage regulators on the Port Waikato feeder to increase backfeed capacity in 2019/20, at an estimated cost of $200,000;
- Replace ABS140 on the Whangarata feeder with an automated switch in 2019/20 at an estimated cost of $35,000;
- Replace ABS189 and ABS222 with automated switches in 2019/20 at an estimated cost of $70,000; and
- Upgrade auto-transformers and install voltage regulators on the Glen Murray feeder to increase backfeed capacity in 2021/22, at an estimated cost of $400,000.

Battery Energy Storage Trial

One of the network alternative technologies which has the potential to change how distribution networks traditionally operate is energy storage through the use of grid scale battery storage systems.

We installed our first grid-scale battery storage system at the Tuakau Zone Substation in 2017. This trial installation was to understand the benefits such systems can provide including management of peak demand, contributing to quality of supply through reactive power support, and to provide ancillary services. While the battery trial has specific objectives, it will more broadly enable better understanding of its impact on the network, its limitations, and the benefits it can provide across the whole network over time.

We believe the battery will provide us with both regulated benefits (in terms of network support and peak demand management on the distribution network), as well as unregulated benefits (such as value from the arbitrage of energy when not used for regulated purposes). As such we discuss the use of the battery in this AMP in the context of our regulated activities however we are working to develop a cost allocation methodology to provide a transparent means of reporting how we use the battery and allocate respective costs and benefits.

Bombay Area

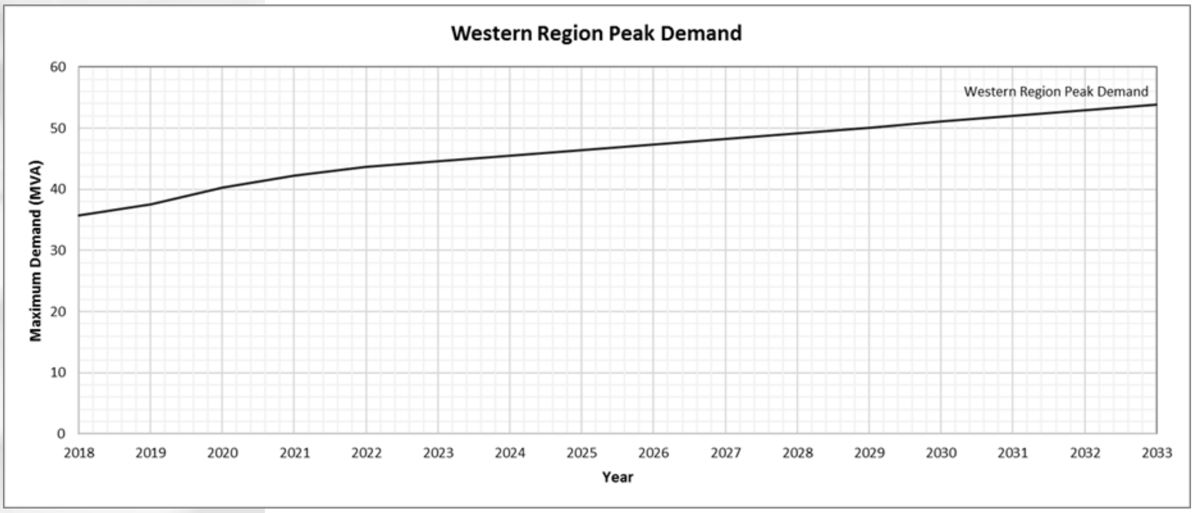
Our development plan for feeders to be supplied from the Bombay Area Zone Substation that will replace the Mangatawhiri and Ramarama substations is to:

- Replace ABS445 on the Ararimu feeder with a recloser to improve network performance in 2019/20 at an estimated cost of $35,000;
- Convert the Bombay feeder (Ramarama) to 22kV operation in advance of establishment of the Bombay area substation in 2020/21, at an estimated cost of $3 million;
- Upgrade the Great South Rd feeder in 2021/22, at an estimated cost of $80,000;
- Convert parts of our distribution network to be supplied from the Bombay Area Zone Substation to 22kV operation in 2023/24 at an estimated cost of $9 million;
- Rebuild a section of the Great South Rd feeder in 2023/24 at an estimated cost of $330,000;
- Create a link between the Mercer feeder and the Pokeno Church feeder to increase backfeed capacity in 2025/26, at an estimated cost of $1 million;
- Upgrade conductor to increase backfeed capacity between the Whangarata feeder and the Bombay feeder in 2027/28, at an estimated cost of $150,000; and
- Split the Kaiaua feeder to improve security, reduce the number of customers on the feeder and increase the backfeed flexibility in 2028/29, at an estimated cost of $1.8 million.

Western Region Development Plans

The Western Region is supplied from the Glenbrook GXP and covers areas supplied by our Karaka, Maioro and Waiuku Zone Substations and a 33kV point of supply at Storey Road. Studies have been undertaken which have established that 33kV is the appropriate and cost effective sub-transmission voltage for this region for the foreseeable future.

The figure below shows the forecast Western Region peak demand.



Western Region – Peak Demand (Winter)

Western Subtransmission

Our development plan for the Western Subtransmission is to:

- Investigate if cyclic ratings can be applied to the Glenbrook Karaka North line in 2019/20, at an estimated cost of $400,000; and
- Investigate if cyclic ratings can be applied to the Glenbrook Waiuku East line in 2019/20, at an estimated cost of $300,000.

Karaka

Our development plan for the Karaka Zone Substation feeders is to:

- Split the Patumahoe feeder to provide backfeed capacity to the Paerata Rise development and defer the proposed new Pukekohe North substation. This work will be completed in 2019/20, at an estimated cost of $540,000;
- Install a voltage regulator and upgrade the autotransformer on the Blackbridge feeder in 2020/21 to increase supply capacity to the Karaka North development in the short to medium term, at an estimated cost of $400,000;
- Install a voltage regulator at switch 47 along the Te Hihi feeder in 2021/22 with an estimated cost of $350,000. This investment is to accommodate the identified load growth on the feeder due to the expected development around Kingseat in the short to medium term;
- Convert the section of the Patumahoe feeder supplying the eastern limb to 22kV in 2021/22 at an estimated cost of $2.2 million. This project is to improve the capacity of the Patumahoe feeder to supply the Paerata Rise development, as the Anchor Factory feeder is forecast to have future customer number and capacity constraints;
- Convert the Blackbridge feeder to 22kV operation in 2026/27, at an estimated cost of $5 million. This investment will provide more system flexibility by enabling us to backfeed load from the proposed large subdivision developments in the Opaheke and Pukekohe north areas; and
- Replace the Karaka 11kV switchboard in 2028/29 to provide the required number of feeder supplies to meet the target of 1,500 customers per feeder, at an estimated cost of $1.2 million.

Proposed new Zone Substations at Kingseat and Glenbrook Beach/Clarks Beach

The present growth in subdivisions in the Glenbrook Beach/Clarks Beach area and the Kingseat Area are now planned to be addressed by establishing new small substations as noted below as the existing feeders become constrained.

The establishment of substantial subdivisions in these two locations will create localised load centres at the end of existing feeders from Karaka and Waiuku. The expected load increase is such that the Karaka substation would exceed firm capacity in 2024/25. Planning studies have established that smaller substations at these two locations would provide the best overall solution. Based on current development rates the first location would be Kingseat expected to be between 2022/23 to 2027/28 to offload the Karaka substation followed by feeder upgrades which should then delay the need for a Glenbrook Beach/Clarks Beach substation until the end of the planning period.

As these constraints are being caused by land development in locations some distance from the existing zone substations and high capacity network areas, the substantial costs relative to the number of customers and expected revenue means that a detailed economic analysis has to be completed for any solutions. A full business case would be required, including analysis of all viable alternatives, and it is expected that the land developers will be required to make significant contributions to funding this infrastructure.

Estimated costs for the total development is $41.7 million of which up to $34.2 million will be within this planning period. This is based on all new equipment, however it may be possible to re-locate some existing items to reduce this estimate, as well as defer timing of some investments beyond this planning period through staged development pathways.

Waiuku

Our development plan for the Waiuku Zone Substation is to:

- Complete the redevelopment of the Zone Substation which has capacity, age and condition issues with a new substation on the same site in 2019/20 at an estimated cost of $3.1 million.

Our development plan for the Waiuku Substation feeders is to:

- Replace ABS261 with a recloser and recloser 905 with an automated switch on the Manukau Heads feeder in 2019/20 at an estimated cost of $70,000;
- Upgrade a total of 3.6km of the Te Toro and Manukau Heads feeders, and install a second voltage regulator on the Te Toro feeder in 2021/22 to increase the backfeed capacity of the two feeders, with an estimated cost of $1.04 million;
- Rebuild the tie section of the Waiuku Town and Te Toro feeders in 2021/22 to increase the backfeed capacity to the Waiuku Town feeder, with an estimated cost of $500,000; and
- Install two new urban feeders from Waiuku switchboard spare circuit breakers to offload the Waiuku Town, Waiuku West and Racecourse Road urban feeders in 2022/23, at an estimated cost of $3.5 million.

Maioro

Our development plan for the Maioro Substation feeders is to:

- Install a voltage regulator on the Otaua feeder in 2021/22, at an estimated cost of $350,000 to address voltage constraints along the feeder.

COUNTIESPOWER

Investment forecasts

Network and Non-Network CAPEX Forecast

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Consumer Connections	12,690	13,100	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
System Growth	26,770	25,950	21,510	20,630	12,200	280	8,400	7,600	14,650	10,400
Asset Replacements	13,360	12,020	11,750	11,490	13,210	16,860	13,620	13,030	12,100	13,150
Asset Relocations	300	300	300	300	300	300	300	300	300	300
Reliability, Safety and Environment	1,195	386	350	350	7,460	350	350	350	350	350
Subtotal Network	54,315	51,756	45,910	44,770	45,170	29,790	34,670	33,280	39,400	36,200
WIP carry-over from FY19 to FY20										
WIP carry-over from FY20 to FY21										
Non Network	6,433	2,626	2,163	1,450	1,499	1,509	1,540	1,590	1,602	1,634
TOTAL	60,748	54,382	48,073	46,220	46,669	31,299	36,210	34,870	41,002	37,834

Network OPEX Forecast

Asset Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Service interruptions and emergencies	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Vegetation management	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
Routine and corrective maintenance and inspection	1,350	1,350	1,360	1,360	1,360	1,360	1,360	1,370	1,370	1,370
Asset replacement and renewal	700	700	700	700	700	700	700	710	740	720
Total	**5,300**	**5,300**	**5,310**	**5,310**	**5,310**	**5,310**	**5,310**	**5,330**	**5,360**	**5,340**

Note: Forecasts are stated in real (constant) prices

1 Introduction

This chapter introduces Counties Power's 2019 Asset Management Plan (AMP) and covers:

- **Purpose:** provides the reasons for producing this AMP, the period it covers, the date it was approved by our Board of Directors (Board), and the assets it covers;
- **Key Themes and Initiatives:** A summary of the key themes and initiatives that have been described in this AMP; and
- **Document Structure:** an outline of this AMP and how it is structured.

1.1 Purpose

The purpose and objective of our asset management practices and this AMP is to assist us in managing our assets over their lifecycle in an efficient, effective and sustainable manner in order to provide a level of service that our consumers want and for which they are willing to pay. This AMP is a vital planning document as it focuses our decisions and activities so that our assets provide enduring value to our consumers, our stakeholders and ourselves. It illustrates how our asset management objectives are aligned to our corporate objectives, mission and values.

We apply a disciplined and consistent approach to the management of our assets, so that we can attain our corporate mission of being a progressive and successful community owned electricity distribution business with the aim of delivering safe, reliable, and cost-effective electricity to our consumers. Our asset management approach converts our corporate objectives of operating a safe network, meeting consumer needs and maximising shareholder returns into technical and financial decisions, plans and activities. This AMP links with our other documented plans that are a part of our business planning process. These documents are our Statement of Corporate Intent, our Strategic Plan, and our annual budget.

1.2 Period covered

This AMP covers the period from 1 April 2019 through to 31 March 2029 (AMP period). As with any long-term planning document, greater detail has been included for the first five years. Planning for the outer period is directional.

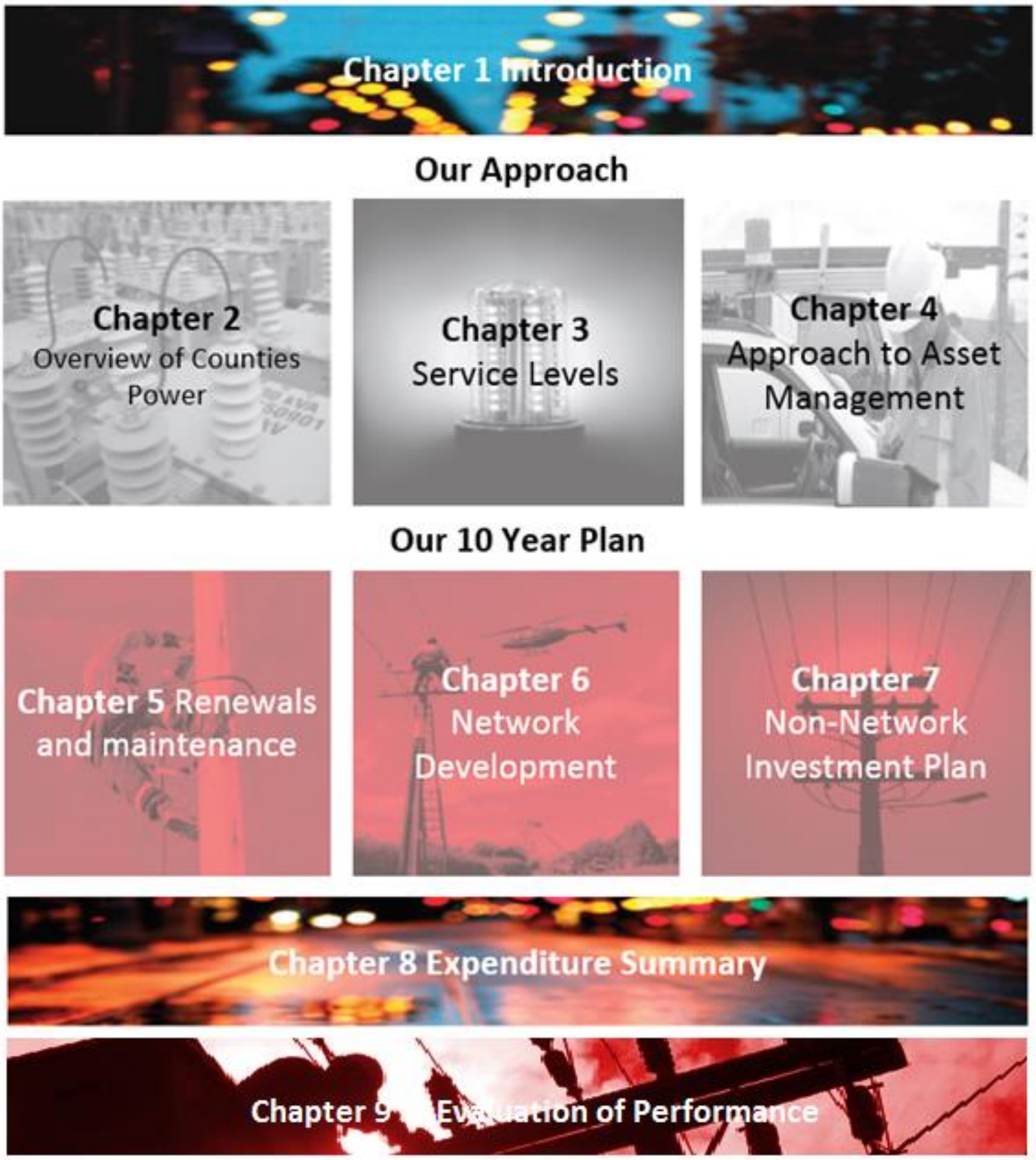
1.3 Approval date

This AMP was approved by our Board of Directors on 20 March 2019.

1.4 Scope

This AMP covers all network equipment and non-network solutions involved in the distribution of electricity to consumers who are connected to our network.

1.5 Document structure



Chapter 2 – Overview of Counties Power – this section provides a brief background of Counties Power, our organisation, our operating environment, outlines who our stakeholders and consumers are, and an overview of our network.

Chapter 3 – Service Levels – this section provides an overview of the service levels we expect to provide to our stakeholders and which inform our asset management decision making.

Chapter 4 – Approach to Asset Management – this section provides an overview of how we go about asset management at Counties Power and describes our framework and process for making investment decisions, including our approach to risk management.

Chapter 5 – Renewals and Maintenance – this section provides a more detailed overview of our assets by category, and includes our plans on how we inspect, maintain and replace them.

Chapter 6 – Network Development – this section provides details on how we forecast our network demand, the capacity of our network to manage that demand and the constraints identified and includes our plans on how we are going to develop the network to address future growth.

Chapter 7 – Non-Network Investment Plan – this section provides details on the investments we will make in non-network equipment such as land and buildings, IT equipment, tools, vehicles and machinery.

Chapter 8 – Expenditure Summary – this section summarises all the operational and capital expenditure identified in Chapter 5, 6, and 7 for the 10-year period covered by this plan.

Chapter 9 – Evaluation of Performance – this section assesses performance against previous plans as part of our continual improvement in asset management and overall business performance.

Appendices A to F provide a glossary of terms, a summary of performance against previous plans, the information disclosure schedules, and director certification.

2 Overview of Counties Power

2.1 Our company

Counties Power owns, manages and operates an electricity distribution network in South Auckland, North Waikato and Hauraki district areas with a system length of 3,200 km covering an area of approximately 2250 km^2. The Auckland Council area covers 830 km^2 (37%) of the Counties Power network, the Waikato District covers 1340 km^2 (60%), and the Hauraki District covers the remaining 80 km^2 (3%). We receive power from the national grid at the Bombay and Glenbrook Grid Exit Points (GXPs) and then transport it to our consumers via eight zone substations and our extensive network of lines, cables, transformers and other equipment.

2.1.1 Ownership and governance

Counties Power is 100% consumer owned. All shares are held by the Trustees of the Counties Power Consumer Trust (Trust) on behalf of all local power consumers. The Trust has a total of five Trustees, of which two are required to be elected every two years. Counties Power is managed for the benefit of its consumers and their communities. The Trust oversees the performance of Counties Power through the appointment of a Board of Directors (Board). The Board and Management of Counties Power consult the Trust on our strategic direction, business plans, and asset management measures and targets. Information about the Trust can be obtained from www.countiespowertrust.co.nz.

Objective

Our objective is to operate Counties Power as a successful electricity distribution and service business, ensuring that the necessary strategies are implemented to maintain an environment of zero harm for our staff, consumers and the communities in which we operate, to provide a reliable service that meets consumer needs and to achieve sustainable and superior shareholder value.

To achieve this objective, we will embrace the concepts of quality, safety and environmental responsibility in all elements of our business. The safety of our staff, our contractors and the communities in which we operate is our top priority. We are committed to continually providing a quality service at competitive prices for the benefit of our consumers. We will continue to invest prudently in developing our assets, focus upon excellence in our core business, deliver on our targets and foster a philosophy of continuous improvement.

Mission

Counties Power's mission is to be a growing and successful consumer-owned electricity company that provides safe, reliable and cost-effective electricity to our consumers, always.

Values

Our values drive how we work and interact. They keep us focused and guide our decisions as we deliver on our objectives and mission. Our values are:

Safe: We deliver on our commitment to safety and our duty of care for our people and the public, always.

Dedicated: We take pride in what we do, our expertise and the level of service we offer.

Reliable: We can depend on each other and the community can depend on us.

Smart: We work hard, share ideas and adapt to meet the challenges of our evolving industry.

Dynamic: We are forward thinking and progressive in our approach.

Informing Asset Management practices

Our objective, mission and values steer our priorities and activities. They also provide the framework for our business and asset management practices. In particular, they inform our asset management practices by having safety as our top priority. Our service levels help link the company vision to the expectations of consumers and to assist us in measuring and improving performance.

2.1.2 Company structure

The Counties Power Board is responsible for the overall governance of the business, including approval of the company strategy, business plans and annual budgets. The Directors are appointed by the Counties Power Consumer Trust. The Board reports to the Trust on a quarterly basis.

The Chief Executive is responsible for leading the business, implementing the company strategy and is accountable for business performance.

The Leadership Team reports to the Chief Executive and is responsible for specific areas of the business operation as shown in the diagram below.

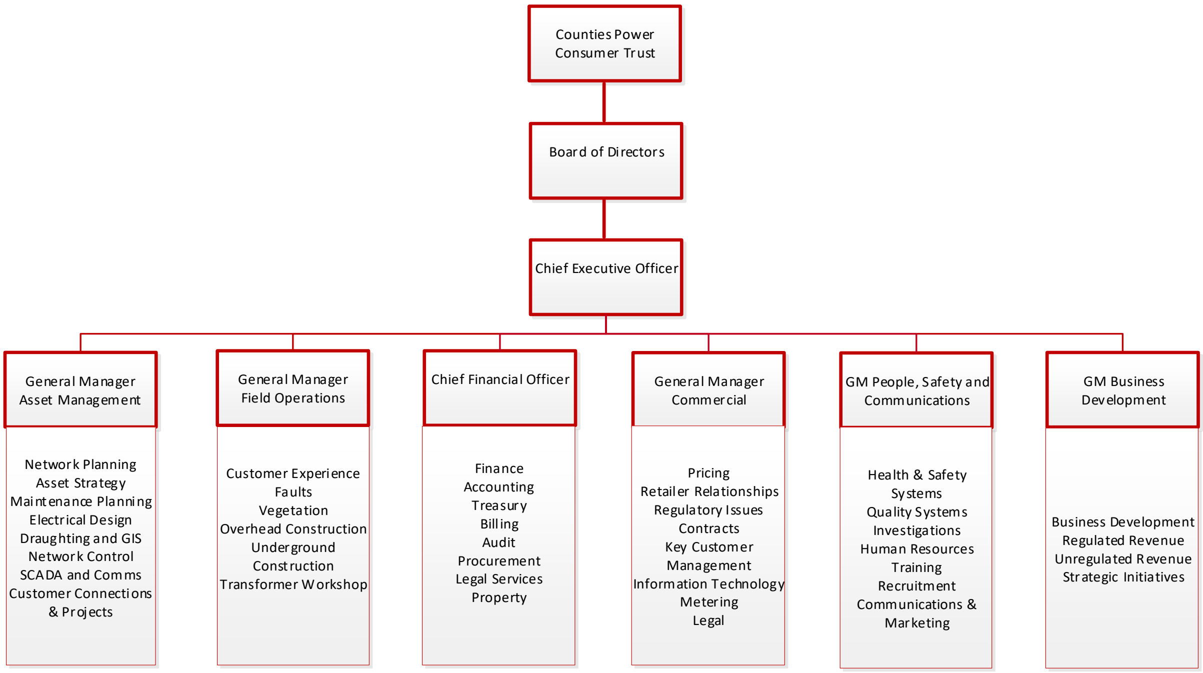


Figure 2-1 Overview of company structure

The General Manager Asset Management is accountable for the asset management function in the business, including developing network planning and asset strategies, compiling and delivering annual plans for operational expenditure and capital investment, as well as the control and operation of the network to ensure the ongoing operation of the network meets safety and reliability expectations.

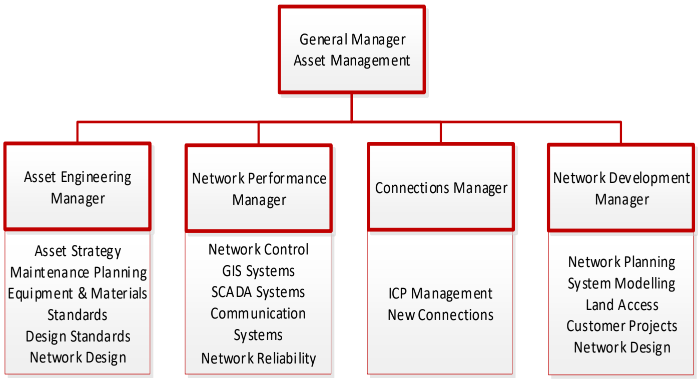


Figure 2-2 Overview of Asset Management Team

The General Manager Field Operations is accountable for the safe and cost-effective field delivery of annual plans and work programmes, including routine and corrective maintenance, asset replacement, construction of new network, fault dispatch and response, customer services, and vegetation management.

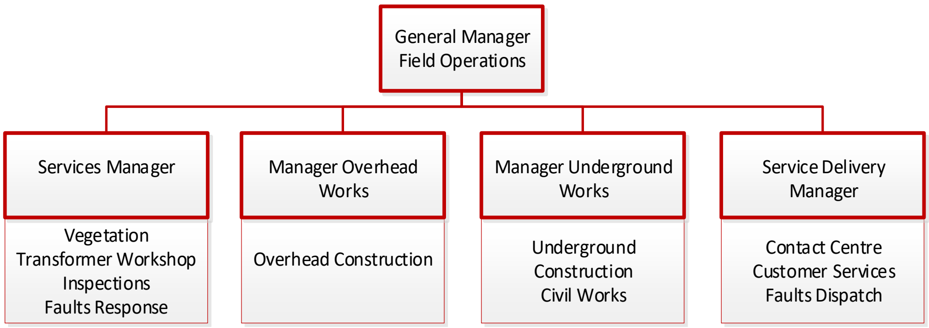


Figure 2-3 Overview of Field Operations Team

2.1.3 Asset Management governance

Expenditure approvals

The Board of Directors approves the annual budgets for operational and capital expenditure and delegates authority to the Chief Executive to approve the expenditure within a delegated authority framework, which is reviewed annually. Each major initiative or project is then subject to a robust business case and options analysis process before being recommended by the sponsoring executive for investment. The Chief Executive delegates authority to management to approve expenditure of a lower level in line with the requirements of the position and responsibilities.

All network capital projects over $100,000 have a business case approval process including a Capital Projects Governance Committee comprising all members of the Leadership Team. All major projects are reported to the Board on a monthly basis and are subject to a post implementation review to ensure objectives and targets have been achieved.

Any project variations which incur a cost increase or material time delay are managed within the approved delegated authority level and reported to the Board as appropriate.

Asset Management capability

In order to deliver this plan, Counties Power has to ensure that appropriate skills and capability are available within the business.

Counties Power undertakes the majority of routine asset management activities in-house, using its own employees. As shown in the organisation structure diagrams earlier in this section, the Asset Management and Field Operations teams develop and deliver this plan, with the support of the Finance, Commercial, and People and Communications teams.

Some activities are outsourced to meet peak capacity requirements, or where it is not efficient to have specialist skills within the team. Examples of specialist services sourced externally include land and resource planning, specialist engineering and advisory consultants, and some field services such as specialist equipment repairers and protection technicians. A robust contractor assessment and approval framework provides assurance of safety, technical and capability competency before work commences and forms part of the ongoing contractor performance assessment framework.

Alongside maintaining worker competency, the training and development of staff is critical to the success of the business and identifying areas where new skills requirements or development pathways exist.

Through the development of a rolling 10-year plan, Counties Power is able to identify the upcoming work types and volume, and assess the requirements for resources, capability and capacity.

2.2 Operating environment

Network Overview

The Counties Power network has traditionally been a provincial 'town and country' network distributing electricity across a broad geography in the southern Auckland and the northern Waikato region. However, the rapid increase in the subdivision of land for housing together with the development of substantial industrial centres at Drury and Pokeno are seeing the substantial growth of the urban areas such that the longer term will see us as primarily an urban network but with a substantial rural sector.

Today, 70% of the Counties Power network is a rural overhead network by length, however the urban networks supplying Pukekohe, Waiuku, Tuakau, Pokeno, Drury and parts of Papakura comprise a split of overhead and underground assets. Generally, the eastern part of the network is newer, higher in ICP density and subject to high levels of growth in the areas adjacent to motorway and state highway corridors. The western side of the network is older, more remote and with a lower ICP density and has been subject to little recent growth. However the establishment of Special Housing Areas and other subdivisions is creating pockets of high ICP growth requiring network reinforcement, especially where they are some distance from existing substations.

Network performance is consistent with a largely rural network topology, largely owing to long restoration times associated with the remote Manukau Heads, Port Waikato and Kaiaua supply areas. Increasing levels of network automation are improving response times. When compared to a peer group of similar networks, the network was historically one of the better performing rural/urban networks in New Zealand, but in recent years has experienced increasing levels of faults due to aging overhead network assets, the increasing frequency and severity of weather events, and operational decisions which have led to a decrease in live work and changes to reclose rules which have contributed to unfavourable network performance. In addition, the ability of a 22kV feeder to provide greater capacity has resulted in some feeders with very high customer numbers fed by them (double typical industry figures) which results in more customers being affected by an incident and poorer performance figures.

Programmes of works outlined in this plan are intended to address these identified network performance issues.

The Counties Power network is exposed to normal climatic variations including temperature, wind and rain variances. The severity and frequency of adverse weather events is noted to be increasing, with short sharp bursts of wind and rain causing damage directly to the network or causing debris to be blown onto lines.

Assets exposed to the harsher weather and environmental conditions of the Awhitu Peninsula are also subject to more frequent failures and have lower expected life spans. Similarly, in some areas overhead assets are located on exposed ridge lines or are in difficult terrain to access and maintain.

Vegetation management is another area of concern to Counties Power. Areas such as Ararimu and Hunua are heavily vegetated which leads to high numbers of tree related outages, and in particular blown vegetation over which Counties Power has little control. A common problem in the area is gum bark which is blown onto lines, causing momentary outages. Counties Power and our vegetation management contractors liaise with the relevant local authorities and landowners concerning trimming and/or removal of trees in accordance with the *Electricity (Hazards from Trees) Regulations 2003*.

Trees interfering with power lines fall into two categories, those that fall into the trimming zones as defined in the above Regulations and those that are outside of this area – referred to as “out of zone” trees. Out of zone trees can be a considerable distance from the lines but, due to their height, will contact the lines if they are blown over.

We are planning in this current year to increase our trimming of trees that have grown “in zone” to minimise outages from such interference.

For out of zone trees we have limited ability under current regulations to take action ourselves and wherever these are identified we liaise with the owner to try to negotiate an acceptable solution. The Regulations are due for review and the industry is seeking to improve its ability to directly address such hazards and to recover the costs involved.

Territorial Authorities

The Counties Power network operates in an area split between three different territorial authorities; Auckland Council (37% of the Counties Power area), Waikato District Council (60%) and the balance in the Hauraki District Council area. Each territorial authority produces its own planning documents with rules which give effect to the Resource Management Act 1991, to promote the sustainable management of natural and physical resources.

Auckland Unitary Plan

Within the area of Counties Power that is administered by Auckland Council, the Auckland Plan 2050 will guide the long term spatial development of the wider Auckland area over the next 30 years. Its aims and objectives are supported by a number of documents including the Future Urban Land Supply Strategy 2017 (FULSS) and the Auckland Unitary Plan Operative in Part (AUP(OP)). The FULSS provides a long term, proactive approach to the delivery and timing of development ready land, providing clarity and certainty upon which to base infrastructure planning and investment decisions. The FULSS has recently been updated to reflect changes brought about by the Special Housing Areas, the AUP(OP) and new demand for development. The AUP(OP) came into effect in 2016 and replaced the former Regional Policy Statements and 12 District and Regional Plans. While there are still a number of outstanding appeals to the plan, (some of which are based in the Counties Power area), which means that it cannot be notified as being fully operative, Counties Power must be mindful of the requirements of the AUP(OP) in the design, construction and maintenance of its network. While these requirements have the potential to add cost and complexity to maintenance and future development of the network, our experience to date has been that these circumstances occur only rarely.

Waikato District Plan

In the southern part of the Counties Power area the rules of the Waikato Regional Plan determine how we undertake work which might impact on the use, development or protection of natural resources; while the district plan rules are provided by the Proposed Waikato District Plan. Stage 1 of the Proposed Waikato District Plan, which was publicly notified in July 2018, combines the Franklin and Waikato sections into a single plan for the Waikato district. The Proposed Waikato District Plan will provide guidance and set the rules that will shape growth and development in the southern part of the Counties Power area for the next 10 years. Submissions on Stage 1 of the proposed plan closed in early October, with further submissions likely to be provided by Counties Power in due course. We note their intention to concentrate development in existing developed areas such as Tuakau and Pokeno.

Hauraki District Plan

In the Hauraki District Council area, the requirements for Counties Power's operation, maintenance and development of the network are still based upon the Franklin District Plan. There are currently no proposals to review the Hauraki or Franklin section to create a single plan with district wide rules.

Growth – present and future

The Counties Power network is one of the fastest growing electricity networks in New Zealand with connection growth in the order of 2 to 3% per annum. This is largely driven by the growth of Auckland and our location within the 'golden triangle' of growth between Tauranga, Hamilton and Auckland.

The population of the area grew by 11.5% between the 2006 and 2013 census periods[6]. Auckland was the fastest growing region, increasing by 8.5% over the same period. Waikato district was ranked in the top 10 territorial areas with a 10.1% population growth. The Hauraki district population decreased slightly overall, however the Kaiaua area population growth increased by 19% (an area which is supplied by Counties Power).

Population growth trends within the Counties Power area are monitored in terms of building consent applications and new connections. The figures produced by Statistics New Zealand for annual population change support high growth projections in our area.

The largest contributor to demand growth in the medium term is expected to be industrial and residential developments around Tuakau, Pokeno, the approved Special Housing Areas at Paerata Rise, the proposed Drury South Business Park, and the Drury and Hingaia areas.

It has long been recognised that the growing population in Auckland is placing increased demands on land for housing, employment and associated infrastructure in the Auckland and neighbouring regions. To promote efficient urban development, while at the same time protecting natural and physical resources, the AUP(OP) has identified land which is potentially suitable for urban development and has defined its limit by means of the Rural Urban Boundary (RUB). The RUB, which gives effect to the AUP(OP)'s Regional Policy Statement regarding urban growth and form, contains sufficient appropriately zoned land within it's boundary to accommodate a minimum of seven years of projected growth at any one time in terms of residential, commercial and industrial demand, as well as corresponding requirements for social facilities. Development of land beyond the RUB such as that proposed at Clarks Beach and Glenbrook Beach can only be achieved through a formal plan change process, thereby providing utility operators the opportunity to comment on the ability to supply the new development and identify any required upgrade. Maps outlining the RUB impact are provided in Section 6 Network Development Planning.

The supply and delivery of development ready land for housing and industrial growth is an important planning issue for Auckland. Figure 2-4 shows the anticipated dwelling capacity in future urban areas from the Greenfield Areas identified in the Auckland Plan Development Strategy, the future urban zoned land identified within the RUB area in the AUP(OP), and both the large future urban areas and the Rural Settlement future urban areas identified in the Auckland Future Urban Land Supply Strategy 2017 (FULSS)[7]. The sequencing and timing of these developments is proposed in the FULSS and

[6] At the time of writing this AMP, the most recent (2018) census data was not available.

[7] The primary purpose of FULSS is to identify the sequencing and timing of the future urban zoned land identified in the AUPOP and how it should be brought forward for development over the next 30 years based on zoning and infrastructure constraints. The FULSS includes development within rural urban areas of Clarks Beach, Glenbrook Beach, Kingseat, Patumahoe and Karaka North in addition to future urban zones areas within the RUB at Hingaia, Opaheke, Drury, Karaka, Paerata and Pukekohe.

provides a basis on which to calculate the scale and location of likely increases in demand on the network. It is noted however that there may be some slippage in the delivery of development ready land. While the timing of these developments is still uncertain, this provides information on the order of magnitude for anticipated dwelling capacity in our network development planning.

Anticipated dwelling capacity for future urban areas 2017 - 2042			
New greenfield areas	Auckland Plan growth projections (2015)	Auckland Unitary Plan (AUPOP)	Auckland Future Urban Land Supply Strategy (2017)
South (Hingaia, Opaheke, Drury, Karaka, Paerata, Pukekohe) FLUSS area (Clarks Beach, Glenbrook Beach, Kingseat, Patumahoe, Karaka North)	55,000	33,000 – 42,000	42,900

Figure 2-4 Anticipated dwelling capacity for future urban areas

Special Housing Areas

The Special Housing Areas which were initiated to help maintain a ready supply of housing land during the preparation and development of the Auckland Unitary plan have been progressively disestablished since the Unitary Plan became operative (in part) in September 2016. These also feature in the FULSS and play a significant role in the first 5 years of sequencing and are part of the transition to longer term proactive planning. Construction has already commenced on many of these sites within the Counties Power area including sites at Belmont, Pukekohe and Hingaia, McLarin Road, Glenbrook, Clarks Beach, Paerata Rise and Bremner Road, Drury. Whilst the final SHA was disestablished in May 2017, private plan changes such as the Bremner Road extension will mean that development sites will continue to be brought forward.

Regulation

Counties Power, as an electricity distribution business, is subject to regulation by the Commerce Commission, under Part 4 of the *Commerce Act 1986*. Due to the ownership structure, it is exempt from the Default Price-Quality Regime, as the consumers are the beneficial owners through the Counties Power Consumer Trust, however it is still required to comply with the Information Disclosure Requirements, of which the production of an annual 10 year AMP is one requirement.

The business is also regulated by the Electricity Authority and is subject to compliance with the *Electricity Industry Participation Code*, both as a distributor and also as a metering equipment provider.

Regulatory changes imposed by the Electricity Authority on other industry participants, such as Transpower, can have a consequential effect on the business, such as the method for determining transmission pricing.

In addition to economic and industry regulation, Counties Power has a range of legislative requirements to meet including *Electricity Act 1992*, the *Electricity (Safety) Regulations 2010*, the *Health and Safety at Work Act 2015*, the *Electricity (Hazards from Trees) Regulations 2003*, amongst others.

2.3 Consumer value and cost reflective pricing

Counties Power's capital and operating expenditure is continuing to grow as its network expands at a time when peak demand is growing twice as fast as sales volume and where average usage per consumer is decreasing. The combination of Counties Power's current volume based pricing, and the fact it has chosen not to increase its distribution prices to its consumers for the 5 years between 2015 and 2019 in an endeavour to improve consumer value, means that distribution revenue per consumer is also decreasing.

As with any electricity lines company, however, most of the company's costs of providing distribution network access are fixed and are associated with building and maintaining infrastructure that can meet peak demand; the variable cost component is driven by the consumer's winter peak demand requiring additional distribution capacity and associated transmission charges. Because consumer volume is increasing at a lower rate than the consumer peak demand is increasing this creates a mismatch between revenue received and costs incurred. Counties Power's current lines charges to its consumers are not directly cost-reflective. Counties Power are currently consulting with retailers in order to establish a roadmap that will introduce pricing that is more cost reflective but have minimal impact to the consumers on our network.

The Company believes that moving to a more cost reflective structure will enable consumer choice and control and ensure fairer pricing to all customers. For these reasons, the Electricity Authority has also instructed all line companies to introduce cost reflective pricing. To do this Counties Power introduced prices that are higher at peak times and lower off-peak. This then sends clear price signals to consumers to reduce their peak time use and save money and reduce costs to Counties Power. It also gives the choice to customers that if they use power during peak times they still can, but they have to pay more to cover the higher costs to Counties Power.

As a consequence, in 2014 Counties Power introduced smart tariffs that provided peak, off-peak and shoulder pricing options for residential and business customers. No retailers opted to use this tariff, and so on 1 April 2016 Counties Power aligned the tariff to Vector's mass market peak and off-peak tariff to encourage retailer uptake. To date, only two retailers have opted to use the tariff, but this is expected to change in the future as the industry moves to cost reflective pricing.

2.4 Stakeholders

Our stakeholders are the people or organisations that can affect, be affected by, or perceive themselves to be affected by our decisions or activities. Stakeholder requirements are important to us and we place considerable focus on identifying and meeting stakeholder expectations. Our stakeholders are described in Figure 2-5 below, along with their requirements, how those requirements are identified and how they are incorporated into our asset management practices.

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Consumers and Customers	Safety; Reliable supply of electricity; at an acceptable quality and price; Effective communication particularly during emergencies and faults; Care of the environment; and Lifelines preparedness.	Meetings; Consumer focus groups; Annual surveys; Special surveys for projects; and Feedback.	Public safety initiatives; Service level targets; Investment in network; Price/Quality trade off; Consumer engagement process; Network development projects for subdivisions and network extensions; and Asset Fleet Management.
Public, Community, Iwi and Landowners	Safety; Lifelines preparedness; Care of the environment; Mana Whenua values and engagement; Protection of property and amenity values; Reconciling land development opportunities with infrastructure routes; and Effective communication regarding access and maintenance.	Meetings; Feedback; and Consultations.	Public safety initiatives; Network Development Planning; Service level targets; and Emergency preparedness planning.
Local Authorities	Alignment with district and regional planning requirements; and Accommodation of population and industrial growth arising from land use changes.	Meetings; and Consultations on appropriate infrastructure development and regional and district plans.	Network Development Planning to ensure planned growth can be accommodated within the identified zones; and Emergency preparedness planning.
Electricity Retailers	Fair contractual arrangements; Transparent, clear billing; suitable tariff structures; and Effective delivery of business to business services.	Industry forums, conferences and seminars; Regular consultation; Electricity Industry Participation Code; and Use of System Agreements.	Service level targets; and Network Development Planning.
Regulators and Governmental Agencies	Statutory and Regulatory Compliance; and Ensure consumers receive a reliable supply of electricity at an acceptable quality and price.	Legislation and Regulations; Consultations; and Industry forums, conferences and seminars.	Network Development Planning; and Service level targets.
Transpower (as Grid and System Operator)	Security of supply; New grid investment and planning provisions; Effective and timely communication; Legislative and Regulatory compliance; and Sustainable earnings from connected and interconnected assets.	Operational standards and procedures; and Regular meetings.	Network Development Planning.

Stakeholder	Requirements	Identification of Requirements	Requirements Incorporated into Asset Management Practices
Board of Directors	Governance; Risk Management; Business direction and sustainability; and Performance of Chief Executive and Leadership Team.	KPIs; and Regular Board Meetings and Directives.	Risk Management integrated into all business processes; and Monthly reporting.
Employees	Safe and enjoyable work environment; Job satisfaction; Work/life balance; Development opportunities; Fair remuneration; and Effective support.	Employee surveys; and Regular employee briefings and communications.	Forward planning of work; Safety Initiatives and reporting; Integration of Risk Management into all processes; and Training.
Contractors	Safety; Commercial treatment and access; Assurance of work continuity; Visibility of forward workload requirements; and Risk management.	Contractual arrangements; and Regular meetings.	Forward planning of work; Safety initiatives and reporting; and Integration of Risk Management into all processes.
Suppliers	Fair, transparent, unbiased selection; Forecast requirements to optimise supply chain; Commercial sustainability; and Risk management.	Contractual arrangements; and Regular meetings.	Forward planning of work; and Network Standards.
Counties Power Consumer Trust	Fair and reasonable rate of return on equity; Incentives to invest and innovate; Good governance; Risk management; Business sustainability; Good reputation with the community; and Good asset management.	Trustee Meetings; and KPIs.	Network Development Planning; Organisation and governance structures; and Integration of Risk Management Half-yearly and annual reporting.

Figure 2-5 Stakeholders and their requirements

2.4.1 Balancing stakeholder requirements

As we have a wide range of stakeholders it is important that conflicting stakeholder requirements are managed appropriately and consistently. Safety is a company-wide priority that takes precedence in resolving any conflicting requirements. Balancing differing requirements are managed in the following order:

- Safety and hazard mitigation;
- Regulatory and legal requirements;
- Contractual requirements;
- Consumer price/quality; and
- Investment requirements.

2.5 Our consumers

Our consumers are our owners. We are predominantly a rural network. However, our network services one of the fastest growing areas in New Zealand. Consequently, the number of active ICPs has increased significantly over recent years and this growth is expected to continue over the planning period covered by this AMP.

Consumer profiles

As at October 2018, there were 42,525 ICPs connected to the Counties Power network with a peak demand of approximately 116 MW and annual delivered energy of 563 GWh in the year ending 31 March 2018. In the most recent winter peaks in 2018, peak demand increased to 128 MW. This number is increasing daily with new residential, commercial and industrial customers being connected. This is changing the customer mix from a predominantly rural, small town and rural commercial base (e.g. quarries, mines, food production) to an urban residential and industrial mix.

A breakdown of the ICP type is shown in the table below:

	ICPs	Delivered GWh*
Direct supply	7	69.6
Time-of-use	166	113.7
Commercial	7,146	114.3
Domestic	35,206	265.6
Total	**42,525**	**563.2**

* Delivered GWh in FY2017/18.

2.5.1 Major consumers

Counties Power has three large direct supply consumers: Watercare Services Limited, New Zealand Steel Limited and Yashili New Zealand Dairy Company Limited. A fourth direct supply agreement has been signed with a customer who will come online in 2019. The three existing large direct supply customers comprise 14% of Counties Power's total electricity volume and this percentage will increase if Watercare expands their Waikato pumping operation and Yashili grows its production volume. Counties Power works closely with these companies to meet their electricity supply requirements and to understand their future expansion plans.

Power demand from Counties Power's other major consumers has grown in recent years and has been driven by local economic and population growth. This growth has seen the mix of major customers change in recent years and this is likely to continue in the future as small companies expand and new companies are attracted to the region.

Counties Power's top consumers are in the following industry sectors:

- Steel production;
- Dairy processing;
- Waste product and material handling;

- Food and produce processing and packing; and
- Timber and construction material processing.

Counties Power's top 11 consumers account for 17% of Counties Power's total electricity volume.

Other consumers with significant or strategically-important loads on our network include:

- Council infrastructure such as pumping stations, streetlights, and community facilities;
- Emergency and essential service providers; and
- Large industrial or commercial users in addition to those listed above.

We consider the needs of all our major consumers when undertaking Asset Management activities:

- **Safety** – we make sure the assets we own which supply them are safe and well maintained, particularly lines and transformers located on their sites.
- **Reliability** – our network should provide the required level of performance in line with the terms under which the consumer has connected.
- **Value for money** – that the price they pay for using our electricity network is competitive.
- **Security of Supply** – our network should provide sufficient security of supply to enable maintenance and faults to be managed with acceptable levels of disruption to consumers.
- **Planning** – we make sure to consider their operations when planning network activities such as switching and outages.
- **Communication** – we communicate openly with our major consumers to understand their business and what's important to them, as well as providing feedback on events that may have impacted upon their operations.

2.5.2 Distributed Generation

Counties Power has eight embedded generators greater than 10kW and 632 embedded generators under 10kW. The eight large embedded generators consist of the following:

- Four hydro schemes operated by Watercare at their Hunua reservoirs. These comprise a 300kW generator at the Wairoa dam, a 300kW generator at the Mangatawhiri site, a 700kW generator at the Mangatangi dam, and a 300kW generator at Cosseys dam;
- A 7MW landfill generation plant at Hampton Downs landfill operated by Envirowaste. This plant comprises seven 1MW containerised landfill generators;
- A 5MW plant in Papakura operated by an electricity retailer (consisting of a 3.5MW gas generator and a 1.5MW diesel generator);
- A 60kW photo voltaic installation at Drury operated by an industrial consumer; and
- A 15kW photo voltaic installation at Counties Power's head office, which includes a 3.6kWh battery storage system to support our day-to-day needs and is also part of the learning and development activities associated with the opportunities afforded by solar photo voltaics and electricity storage systems.

The remaining 632 embedded generators under 10kW are nearly all small residential and business photo voltaic installations. The number of photo voltaic installations has grown rapidly over the last two years.

2.5.3 Energy delivered and demand

Counties Power's total delivered electricity in the year to 31 March 2018 was 563 GWh and peak demand was 128 MW. The network load profile is winter peaking, with residential loads showing typical morning and evening peaks, and commercial loads generally having a constant daytime load.

Delivered energy has been growing at 1.8% per annum on average over the last 5 years and peak demand has grown at an average of 3.7% per annum over the same period. The graph below shows the growth split over Counties Power's main consumer groups and the peak demand increase.

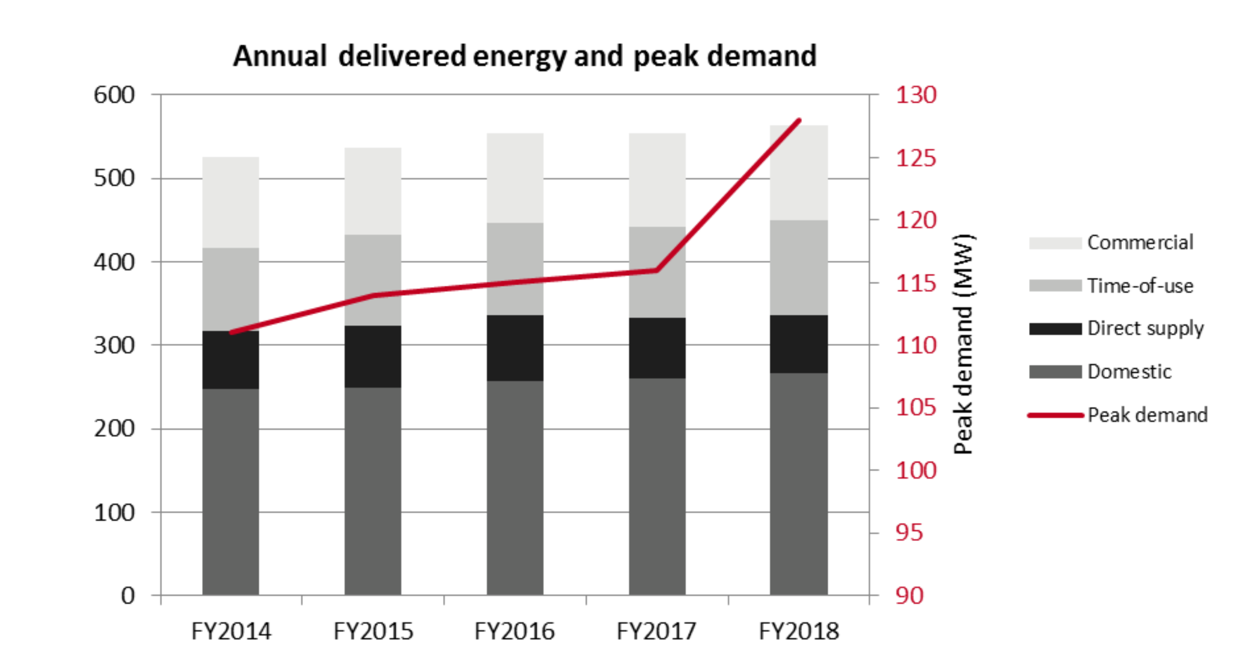


Figure 2-6 Energy volumes and network demand 2014 to 2018

2.6 Our network

Counties Power has two points of supply from Transpower's National Grid via Grid Exit Points (GXPs) at Glenbrook and Bombay. The Glenbrook GXP supplies our western substations at 33kV whilst Bombay GXP supplies the eastern substations at 110kV and 33kV. The number of active installations and the installed distribution capacity controlled by each GXP is shown in Figure 2-7. 73% of ICPs are supplied from the Bombay GXP at 110kV and 33kV, and the remaining 27% from Glenbrook GXP. Other details are included in the following sections.

GXP	Zone Substation	No. of Distribution Substations	Distribution Capacity (kVA)	Active ICPs				
				Total	Residential	Commercial	Industrial	% of Total ICPs
Bombay 110 kV	Pukekohe	657	79,800	12456	10328	2064	64	29%
Bombay 110 kV	Opaheke	486	63,850	8413	7466	908	39	20%
Bombay 110 kV	Tuakau	768	49,223	5914	4723	1163	28	14%
Bombay 33 kV	Mangatawhiri	446	21,380	2171	1601	557	13	5%
Bombay 33 kV	Ramarama	355	18,465	2258	1790	461	7	5%
Glenbrook 33 kV	Karaka	459	26,145	3694	3032	657	5	9%
Glenbrook 33 kV	Maioro	136	19,275	527	347	176	4	1%
Glenbrook 33 kV	Waiuku	668	41,610	7092	5919	1160	13	17%

Figure 2-7 Overview of Network Substations and Consumer Information (as at Oct-18)

Figure 2-8 below illustrates the geographical area covered by the network, along with Figure 2-9 which shows the 110kV and 33kV subtransmission network, the zone substations and the 22kV switching station. More detailed maps showing the distribution network coverage areas, are included in Appendix E – Network Diagrams.

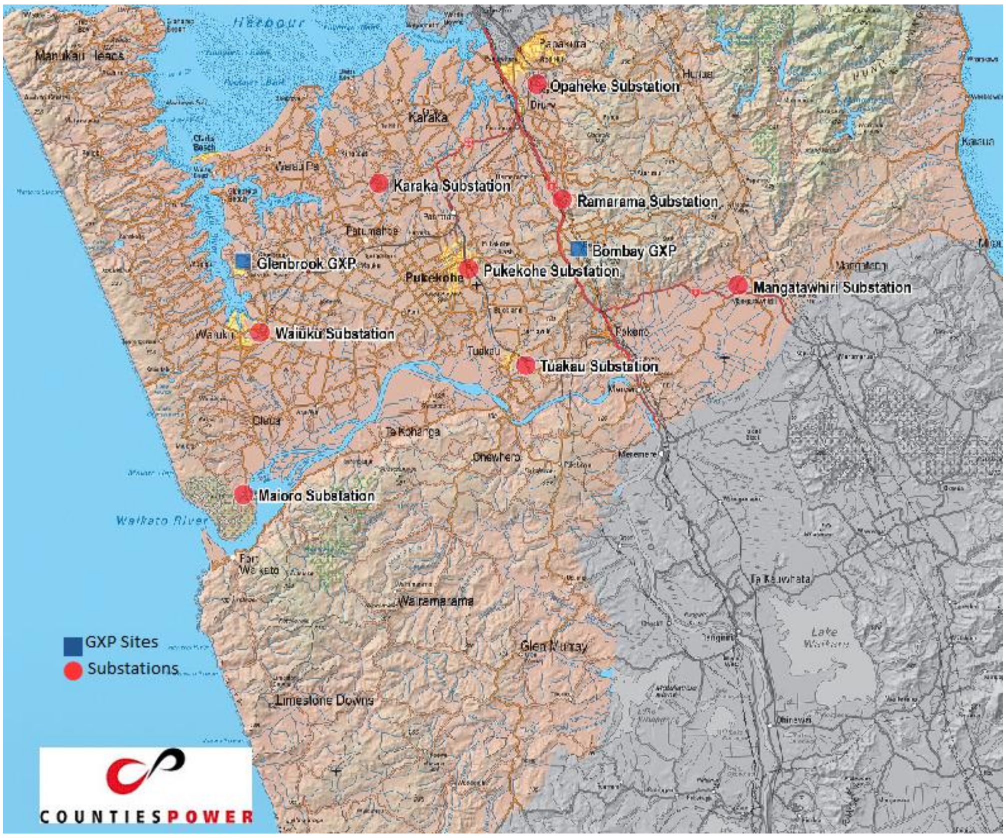


Figure 2-8 Geographic overview of the Counties Power Network Area

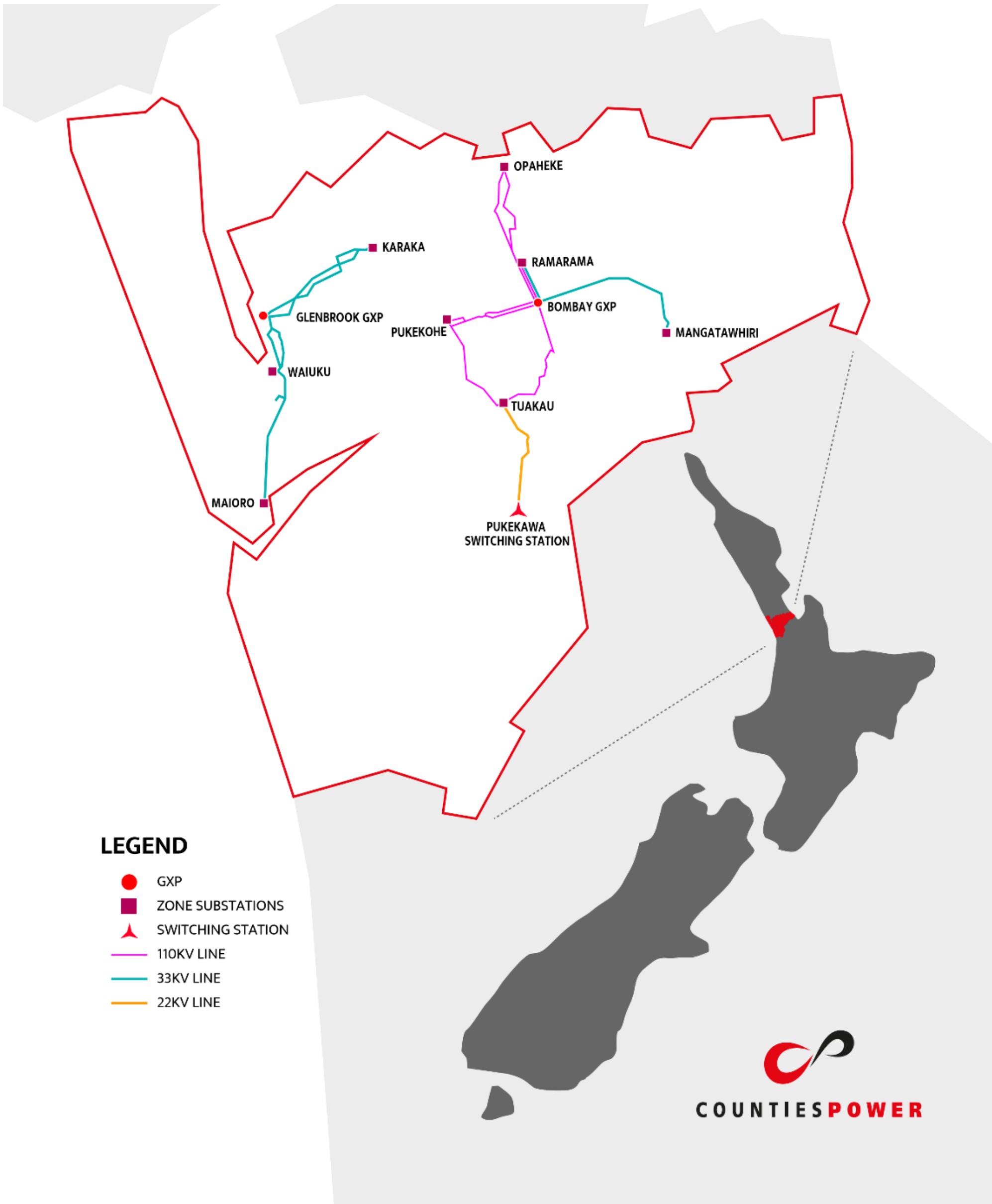


Figure 2-9 Overview of Counties Power Subtransmission Network

2.6.1 The subtransmission network

Our subtransmission network consists of a network of 110kV and 33kV subtransmission lines from Bombay and Glenbrook GXPs. The architecture of the network is typically radial subtransmission circuits connecting to 33kV buses or configured as transformer-feeders where no bus is installed. Our 110kV supply to Pukekohe and Tuakau is operated as a ring with three circuits supplying the two zone substations.

- The Pukekohe Substation is supplied via two 110kV lines from Bombay, with a 110kV bus and two 110/22kV transformers rated at 30/60MVA, with the distribution supply operating at 22kV;

- The Opaheke Substation is supplied via two 110kV lines from Bombay configured as transformer-feeders and has two 110/22kV transformers rated at 20/40MVA, with the distribution supply operating at 22kV; and
- The Tuakau Substation is supplied via two 110kV lines - one from Bombay and one from Pukekohe - and has a 110kV bus with two 110/22kV 20/40MVA transformers. The distribution supply operates at 22kV.

The remaining five zone substations are supplied via the 33kV subtransmission network with distribution supply operating at 11kV, with some feeders stepped up to 22kV using auto transformers.

The subtransmission system schematics, capacity and demand information is provided in Section 6 Network Development Planning. A summary of the loading and other characteristics of the subtransmission system and zone substations are illustrated in Figure 2-10.

GXP (Grid Exit Point)	Zone Substation	Number of GXP circuits	Circuit Description	Installed Capacity (MVA)	N-1 Capacity (MVA)	Load 2018 [2017] (MVA)	No. of Custo-mers (Oct-18)	Average Forecast Growth Trend (%)
Bombay 110kV	Pukekohe	2	Single 110kV pole line	2 x 30/60	60	37.2 [35.2]	12,456	4.0
Bombay 110kV	Opaheke	2	Single 110kV tower line & pole lines	2 x 20/40	40	24.7 [23.9]	8,413	7.2
Bombay 110kV	Tuakau	2	Single 110kV pole line	2 x 20/40	40	16.5 [16.7]	5,914	11.6
Bombay 33kV	Ramarama	2	Single 33kV tower & pole lines	1x5+ 5/6.25	5	6.8 [6.2]	2,258	1.0
Bombay 33kV	Mangatawhiri	1	Single 33kV pole line	1 x 7.5/9.4	--	6.7 [6.1]	2,171	1.0
Glenbrook 33kV	Waiuku	2	Single 33kV pole line	2 x 10/20	15	17.4 [16.0]	7,092	2.7
Glenbrook 33kV	Karaka	2	Single 33kV pole line	2x 10/20	20	11.8 [10.4]	3,694	8.3
Glenbrook 33kV (via Waiuku)	Maioro	1	Single 33kV pole line	2 x 7.5/9.4	--	9.7 [10.0]	527	0.0

Figure 2-10 Summary of Subtransmission and Zone Substations Characteristics

2.6.2 The distribution and LV network

Our zone substations supply a total of 53 distribution feeders (operating at 22kV or 11kV) via approximately 4,052 distribution substations (including private substations). The distribution substations connect over 42,525 consumers to the Counties Power network.

Distribution substations transform the 22kV or 11kV distribution voltage to 400V/230V reticulation voltage.

Distribution substation assets typically include - distribution transformers, high voltage fuses or circuit breakers and low voltage fuses.

A total of 47 22kV/11kV transformers, the earliest of which were installed in 1994, are also in use on the network to provide interconnection between circuits operating at each voltage.

Of the total distribution network circuit length (both HV and LV), 71% consists of overhead lines and 29% is underground cable. On the low voltage network, approximately 55% is overhead whilst on the high voltage network, 87% is overhead (see Figure 2-11). Further details about the distribution network, including quantities and age profiles are included in Section 5 Renewals and Maintenance. In addition to our distribution network, there are overhead lines owned by private land owners which connect to our network, and in places third party poles are used to support overhead lines such as those owned by Chorus. A comprehensive pole survey was undertaken in 2017 to identify private and third party pole ownership to avoid future conflicts of ownership and establish maintenance responsibilities.

Secondary assets include ripple injection systems, protection, SCADA and telecommunication systems.

	Voltage	Length (km)
Underground	22kV	151
	11kV	76
	LV	685
Overhead	22kV	571
	11kV	895
	LV	732

Figure 2-11 Composition of Distribution Network (as at Sep-18)

If we undertake voltage conversion projects, we increase the system length of 22kV network, and decrease the length of 11kV network. All new network extensions are constructed for 22kV operation however may only be energised at 11kV.

Generally, distribution overhead lines and underground cables feed ground-mounted or pole-mounted transformers via fused switchgear such as drop out fuses (DDOs) and ring main units. These distribution transformers step the voltage down to a low voltage level of 400V or 230V to supply our consumers through our low voltage network.

2.7 Our assets

Asset Category	Type	Quantity[1]
Subtransmission		
Poles	Concrete Pole	1,345
	Wooden/other Pole	11
	Steel Pole	147
	Steel Tower	10
Lines	110kV	65.8 km
	33kV	72.3 km
Cables	33kV	1.1 km

Asset Category	Type	Quantity[1]
Zone Substation		
Substation Buildings		9
Power Transformers	110/22kV	6
	33/11kV	9
Circuit Breakers	110kV CBs	14
	33kV CBs	12
	22kV CBs	44
	11kV CBs	36
Station Disconnectors	110kV Disconnectors	2
	33kV Disconnectors	29
Distribution and LV lines		
Poles	Concrete Pole	24,575
	Wooden Pole	1,922
	Other Pole	70
Cross Arms	Wooden/Steel	47131
Conductors	22kV	570.6 km
	11kV	894.6 km
	Low Voltage (LV)	732.1 km
Distribution and LV cables		
Distribution Cables 22kV	XPLE	151.2 km
Distribution Cables 11kV	PILC	19.9 km
	XLPE	55.7 km
LV Cables	PVC	86.9 km
	XLPE	533.7 km
	Other	64.0 km
Street Light Cables	PVC	43.8 km
	XLPE	1.7 km
	Other	2.2 km
Distribution Substations and Transformers		
Distribution Transformers	Pole mounted	3,145
	Ground mounted	830
Auto Transformers		47
Distribution Switchgear		
Ring Main Units		213
Air Break Switch	11kV	126
	22kV	91
Gas Insulated Switch[*2]	11kV	64
	22kV	66
Spur Line Isolator	11kV	841
	22kV	650
Reclosers[*3]	11kV	8
	22kV	23
Grid-scale battery storage system		
Grid scale battery storage system		1
Other System Fixed Assets		
LV Pillars and Pits		13,014

Asset Category	Type	Quantity[1]
Capacitor banks		29
Voltage Regulators		7
Protection relays		144
Load control relays		3,460
Ripple Injection plant		5
Auxiliary battery banks		27
Remote Terminal Units		289

Notes:
1: Asset quantity as at Sep-18.
2: All Gas Insulated Switches are rated at 22kV, operating voltage are as shown in the above table.
3: All Reclosers are rated at 22kV, operating voltages are as shown in above table.

3 Service Levels

3.1 Stakeholder engagement

3.1.1 Customer surveys

Counties Power conducts customer surveys at least once every two years, and post-service feedback surveys every month. The customer surveys measure and monitor both residential and commercial customers experience and rating of the power supply service they receive. The last customer survey was conducted in December 2017 by an external research company. The respondents surveyed were across four consumer groups, defined by rural or urban location and residential or commercial consumers.

	Residential	Commercial	Total
Rural	128	20	148
Urban	228	24	252
Total	356	44	400

Figure 3-1 Distribution of Consumers Surveyed

The 2017 survey evaluated current satisfaction levels in addition to identifying the key factors that influence overall satisfaction. Reliability of supply remains key to satisfaction, but scored low on the importance to our consumers, reflecting that in general most consumers are satisfied with the reliability of their power supply (79%).

Communication was a key influencer and was the top priority identified by the survey. Consumers are demanding greater insights when power is interrupted to enable them to better manage their needs. A core focus of FY19 is the implementation of real-time updates and the diversification of communication channels to deliver timely and accurate data on outages.

Understanding of the value delivered through line charges is of importance to our consumers and is an area of opportunity for the Company, although given poor recognition of Counties Power as their local lines company suggests consumers do not fully understand the components of their overall electricity bill and the difference between lines and energy charges. Of those surveyed, 68% of consumers were unwilling to pay more for increased reliability, reflecting both the current understanding of how lines charges are invested back into the network and the relatively high satisfaction of current reliability of power supply. Those consumers who experienced more outages were more willing to pay increased line charges for increased reliability.

Communication of unplanned outages and information on the annual Counties Power discount were of equal importance to our consumers as the reliability of power supply. Insight from the 2017 survey questions showing the top five service elements which are of importance to our consumers and the current performance valuation are illustrated below in Figure 3-2.

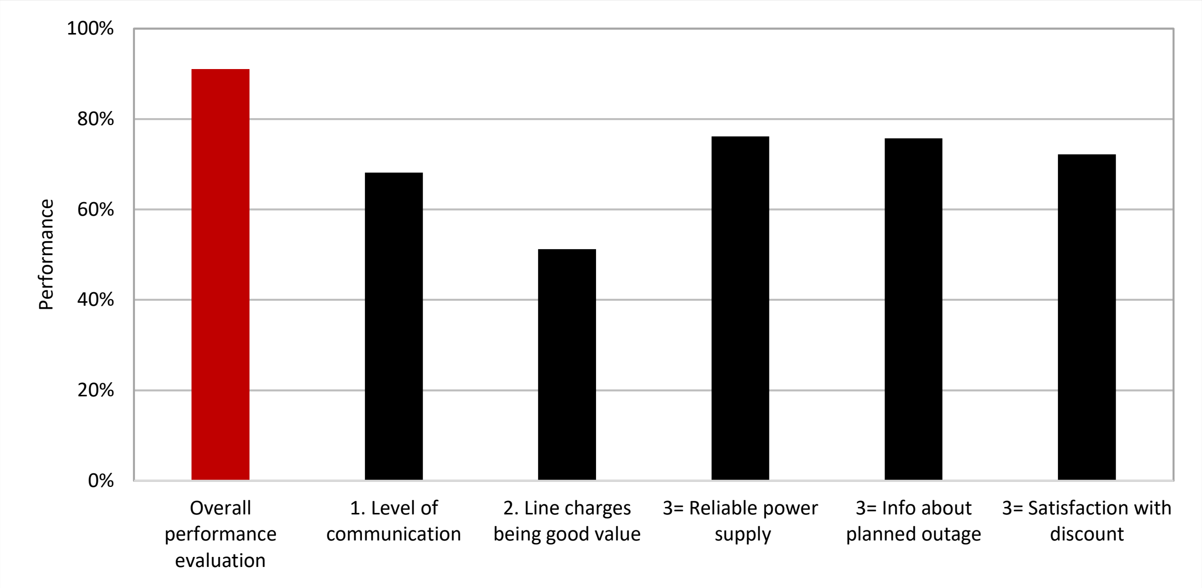


Figure 3-2 Results of 2017 survey questions on top five service elements of importance to our consumers

3.2 Service level: Workplace safety

Our health and safety vision is "no harm for our people, our communities and the environments in which we operate". Our health and safety vision aligns with our corporate mission and values. To achieve our safety vision, our safety culture has continued to improve in the last 12 months due to the implementation of:

- The stronger promotion of reporting and investigation of all near misses, incidents, injuries and damage to plant, equipment or the environment. There has also been emphasis on increasing the number of safety observations and safety conversations on site;
- Strengthening of our staff engagement in safety through a higher profile health and safety committee, with actions and progress reviewed by senior management and the Board;
- The introduction of safety KPIs in all employee's performance objectives;
- Leadership training with key leaders across our business with a focus on safety leadership and skill coaching techniques to enable leaders to develop into effective people leaders; and
- Improved accident and incident investigation and analysis by training management representatives in Incident Cause Analysis Method (ICAM) investigation techniques.

Counties Power is an active member of the Business Leaders' Health and Safety Forum, the Electricity Supply Industry (ESI) Health and Safety Forum, is represented at the Board level of the Electricity Engineers' Association (EEA) and the Electricity Networks Association (ENA) and is a regular contributor to industry working groups on matters concerning staff and public safety and safety by design.

3.2.1 Safety objectives

To achieve our health and safety vision, and our corporate mission and values we have placed health and safety as the highest priority over all our business objectives. We believe that our most important priority is the health and safety of our staff, our contractors, and visitors to our sites and the public who interact with our assets. To this end, we will always conduct ourselves in a manner that protects the health and safety of our employees and contractors (Counties Power Team Members') visitors to our sites and members of the public who interact with us and our assets.

We acknowledge our responsibilities for maintaining high health and safety standards in the work place and will provide competent resources and effective systems and sufficient capacity within our business to fulfil this commitment. All Counties Power employees are required to adhere to this policy.

3.2.2 Safety measures and targets

We have grouped our safety performance targets into two categories; namely lagging indicators through Injury Frequency Rates and leading indicators. These are:

- **Leading Personnel Behaviour Rate Measures.** This includes safety audits in order to improve our safety culture. Under this category we measure Safety Audits, and Safety Observation Reporting.

	Actual 2017/18	Actual 2018/19 (6 months to Sep-18)	Annual Target 2018/19-2027/28
Safety Audits	384	435	132
Safety Observations	1,194	492	1,500
Leadership Team Safety Observations	84	57	84

- **Lagging Injury Rate Measures.** Under this category we measure total recordable injury frequency rate (TRIFR) which encompasses all lost time, restricted work and medically treated injuries using a calculation based on 1 million hours. We also measure lost time injury frequency (LTIFR) and lost time injury severity (LTISR) which encompasses total number of lost time injuries and total lost days. Our company wide target for each measure is to reduce to zero. The only LTI in the year to date was a fall from height.

	Actual 2017/18	Target 2018/19	Actual 2018/19 (6 months to Sep-18)	Targets 2018/19 to 2027/28
TRIFR	7.15	5.35	6.11	Reduce to 0
LTIFR	3.87	2.90	3.34	

3.2.3 Safety initiatives

In order to achieve these objectives, we are undertaking the following initiatives:

- Introduction of the Bowtie methodology for evaluating each critical health and safety risk and the associated controls to ensure robust measures are in place;

- An online system to provide Counties Power employees electronic access to record, report, log and investigate incidents, safety observations, vehicle inspections and site audits;
- A reward and recognition scheme for those who make substantial contributions to safety;
- Continuous promotion of worker engagement through an active Health and Safety Committee;
- Continued engagement with the workforce through a strong worker representation at the Health and Safety Committee;
- Subjecting each high potential incident to a detailed Incident Cause Analysis Methodology (ICAM) investigation by specially trained managers;
- Review of Job Safety Analysis (JSA) to ensure relevancy and identification of gaps; and
- An elevated level of Field audits is also to be completed by an external auditor.

Safety Culture and Leadership

The Counties Power safety culture has continued to improve in the past 12 months, with the ongoing promotion of incident reporting and safety observation reporting for all personnel.

Leadership training has been undertaken with leaders across the business, not only with a focus on safety leadership but also with a focus on developing capability in the area of coaching techniques. This enables staff to further develop as effective people leaders.

Critical Risks

Counties Power's six critical safety risks are:

- Working at height;
- Driving;
- Working with electricity;
- Mobile or moving plant;
- Manual tasks; and
- Asset integrity.

3.3 Service level: Public safety

3.3.1 Objectives

Our objective is to ensure that no member of the public is harmed by our network assets, and that hazards introduced by our network assets are controlled so as to not pose a risk to the public.

3.3.2 Targets

Leading indicators

Categories for leading public safety indicators include:

- Number of Asset Inspections and Tests undertaken on:

- High risk asset categories in the public domain – pillars, transformers, ring main units, poles, zone substations;
- Safety critical assets – earthing, protection systems; and
- Assets in special locations – those located around schools, public recreation spaces, commercial and shopping areas.

- Time to repair high risk defects on the network (percentage completed within required timeframes); and
- Number of external stakeholder engagement activities such as public safety notifications and school safety visits.

Lagging indicators

In addition to leading indicators, we record lagging indicators including:

- Number of incidents reported with or without harm; and
- Number of damaged property incidents (consumer premises and network property).

Actual Performance for FY 2017 to FY 2019 are shown in the table below.

Details	FY 2017	FY 2018	FY 2019 YTD[8]
Property Damage to Network Assets	273	225	197
Reported Injuries from Network Assets	2	2	0

Along with introducing targets for leading indicators, we are also going to extend our reporting of lagging metrics, including:

- Number of assets found or reported to be insecure; and
- Number of lines down and unassisted pole failure incidents.

3.3.3 Initiatives

In order to provide the highest levels of public safety, we have the following initiatives in place:

- Ensuring assets are inspected, maintained and defects repaired in accordance with good industry practice;
- That equipment is designed, selected and installed in a way to promote public safety (safety by design);
- That earthing and protection systems are designed, tested and operate to clear faults quickly to protect members of the public from electric shock;
- Maintain compliance and certification to the requirements of NZS7901 for Public Safety Management Systems, including undertaking periodic external performance assessment;
- Public Safety awareness – undertaken print, web and social media awareness campaigns, as well as engaging with local primary and secondary schools and providing safety resources on our website www.countiespower.com; and

[8] FY2019 YTD is to Sep-18.

- Active engagement with Energy Safety in relation to unsafe activity around our network by third parties, or where people have come to harm from our assets, or their own premises.

3.4 Service level: Reliability

3.4.1 Objectives

Our objective is to operate the network to provide a level of performance in line with the price consumers are willing to pay, this includes:

- Minimising the number and duration of outages experienced by consumers;
- Restoring power as quickly and safely as possible following an unplanned outage and providing communication to keep consumers informed; and
- Providing consumers with sufficient notice ahead of planned outages required for maintenance.

There are some consumer groups on our network who demand higher levels of reliability, and are prepared to pay more for that benefit, and we accommodate their needs where practicable.

3.4.2 Targets

Consumer reliability service levels

We set reliability service levels for our consumers in the Use of System Agreements we have with Retailers trading on our network. These outline the target times for restoration of supply following a fault on the network, as well as the timeframes for notifying the consumer that we have to turn them off for planned works.

Description	Target
Restoring electricity supply after the Distributor becomes aware of the fault.	Rural – 6 hours Urban – 4 hours
Notice of pre-planned supply interruption	Not less than 5 days' notice to the Retailer unless already agreed with by the Customer

Overall network performance

As an exempt EDB, our network performance indices have not been required to be calculated in accordance with the Commerce Commission default price-quality path (DPP) methodology, although we have taken that into account when assessing network performance. We note that the reference period 2004 – 2014 used for the Commerce Commission reliability calculation included a large period of relatively benign weather compared to recent weather trends, the network assets were in places 10 years newer, and the widespread use of live line techniques during that period means that the reference years are not necessarily representative of future network performance. Historic SAIDI and SAIFI is shown in figures 3-3 and 3-4 below.

With the introduction of the Health and Safety at Work Act in 2015, we have implemented a risk based live work decision framework aligned to the Electricity Engineers' Association's guide to live work which has resulted in an increased number of planned outages to complete our work safely. At present, there is a mixed level of adoption of these live work guidelines across the industry, thus making it difficult to benchmark SAIDI and SAIFI performance against our peers.

Our performance targets have been set based upon recent network performance over the period 2014 to 2017, which has been used to set an internal target of 110 minutes for unplanned SAIDI throughout the planning period, and an internal target of 90 (180 non-normalised) minutes for planned SAIDI in 2019/20, giving a total target of 200 SAIDI minutes. Our SAIFI target for 2019/20 has been set at 2.80.

Internally we track planned SAIDI and SAIFI figures utilising the Commerce Commission's Default Price Path (DPP) methodology, which enables us to halve the SAIDI impact of planned outages. By adopting this position on planned SAIDI, and coupling this with reduced live work, we are able to undertake more planned work de-energised, an important safety improvement, as well as reducing the dependence upon generator support. Customer service expectations are being carefully managed, as is engagement with communities in the reasons behind this important safety improvement initiative. We have worked with our main stakeholder, the Counties Power Consumer Trust, to improve their awareness and understanding of the increase in planned outages which, whilst inconvenient in the short term, allows for the maintenance and replacement of assets which will deliver improved performance over the long term.

Given the decline in network performance over recent years as indicated by SAIDI and SAIFI, there is a specific programme in place to reduce the number and impact of unplanned outages. As such, planned SAIDI and SAIFI targets will be maintained at current levels to deliver the works programme, which also comprises of network development and maintenance driven projects.

At the time of writing, our unplanned SAIDI performance in the 2018/19 year is unfavourable to target, largely due to the April 2018 storm event in Auckland which resulted in 61 unplanned outages and contributed 38 SAIDI minutes. We have also had large impacts from unplanned outages affecting high customer density feeders. We forecast a year end position of 170 unplanned SAIDI minutes, and unplanned SAIFI of 2.90 (this is an increase of 0.35 on our initial estimate of 2.55).

Our performance and targets are shown in the table below.

Network SAIDI[9]	2016	2017	2018	2019	2020	2021+ Target[10]
Counties Power	118.3	236.6	270.9	205	200	200
Industry Average	162.9	194.8	216.4			

[9] Network SAIDI figures from 2015 onwards are normalised figures using the Commerce Commission DPP methodology

[10] Total SAIDI targets will reduce from 2020 onwards in line with the reliability investments that are made and forecast benefits they will provide. The future level of reliability investment and expected performance benefits will be assessed in the coming year.

Network SAIFI[11]	2016	2017	2018	2019	2020	2021+ Target
Counties Power	2.70	3.28	3.34	2.90	2.80	2.80
Industry Average	1.88	2.07	2.27			

Faults per 100km	2016	2017	2018	2019	2020	2021+ Target
Counties Power	18.41	18.51	23.32	14.50	14.50	14.50
Industry Average	28.23	24.45	31.59			

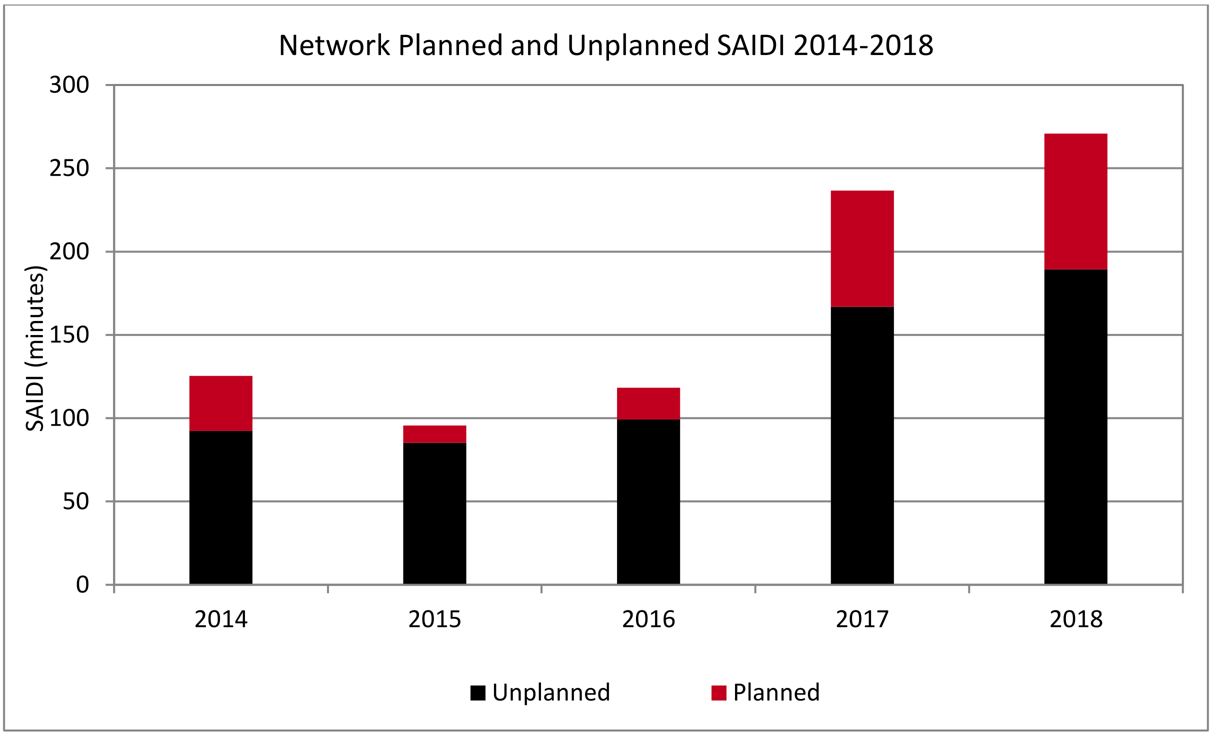


Figure 3-3 Historic Network SAIDI 2014 – 2018 utilising DPP normalisation

[11] Network SAIFI figures from 2015 onwards are normalised figures using the Commerce Commission DPP methodology

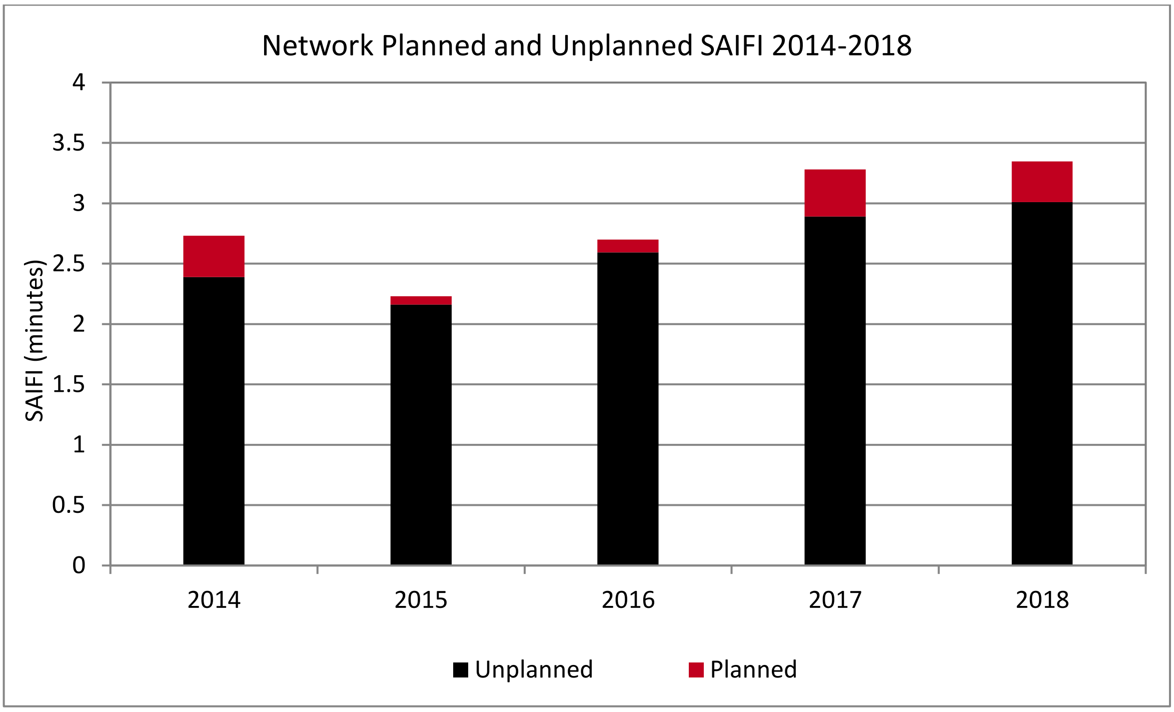


Figure 3-4 Historical Network SAIFI 2014 – 2018 utilising DPP normalisation

The following graphs show our SAIDI and SAIFI[12], and faults per 100km performance against the industry. Our own total SAIDI figure was split 60% unplanned and 40% planned.

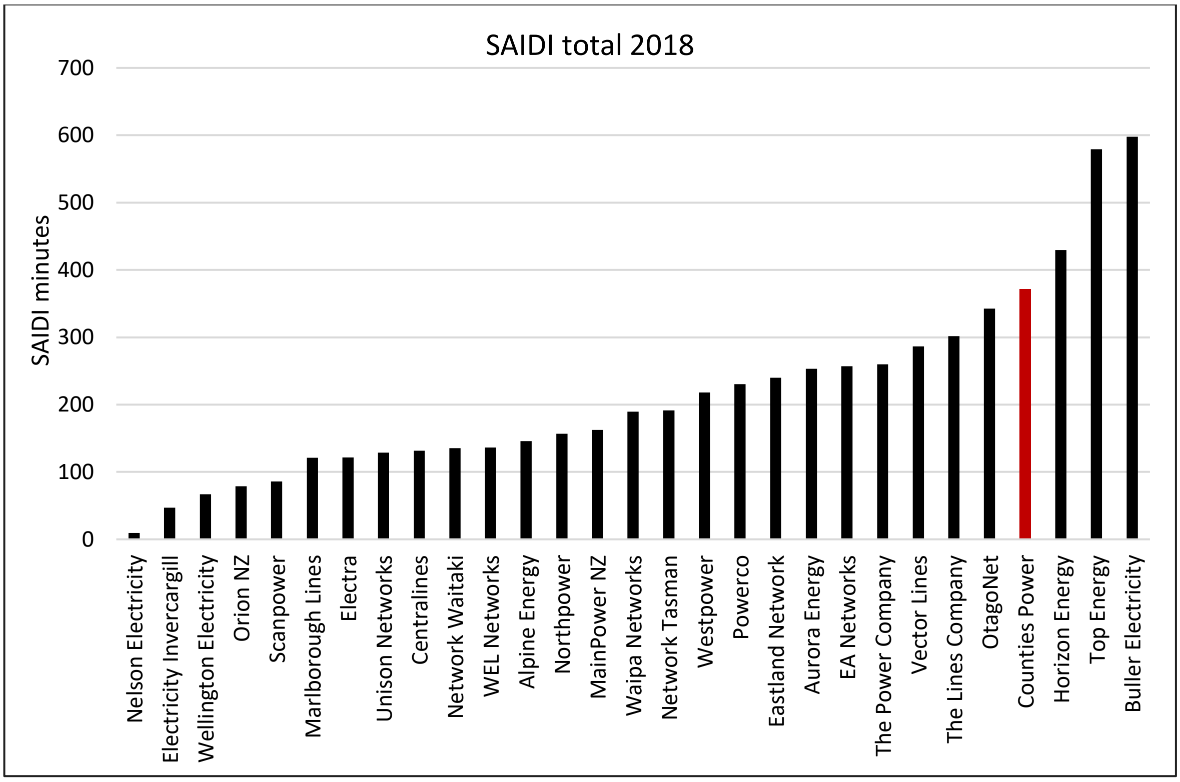


Figure 3-5 Normalised network SAIDI utilising ID normalisation – Industry Comparison 2018

[12] Industry SAIDI and SAIFI figures are normalised values using the Commerce Commission ID methodology.

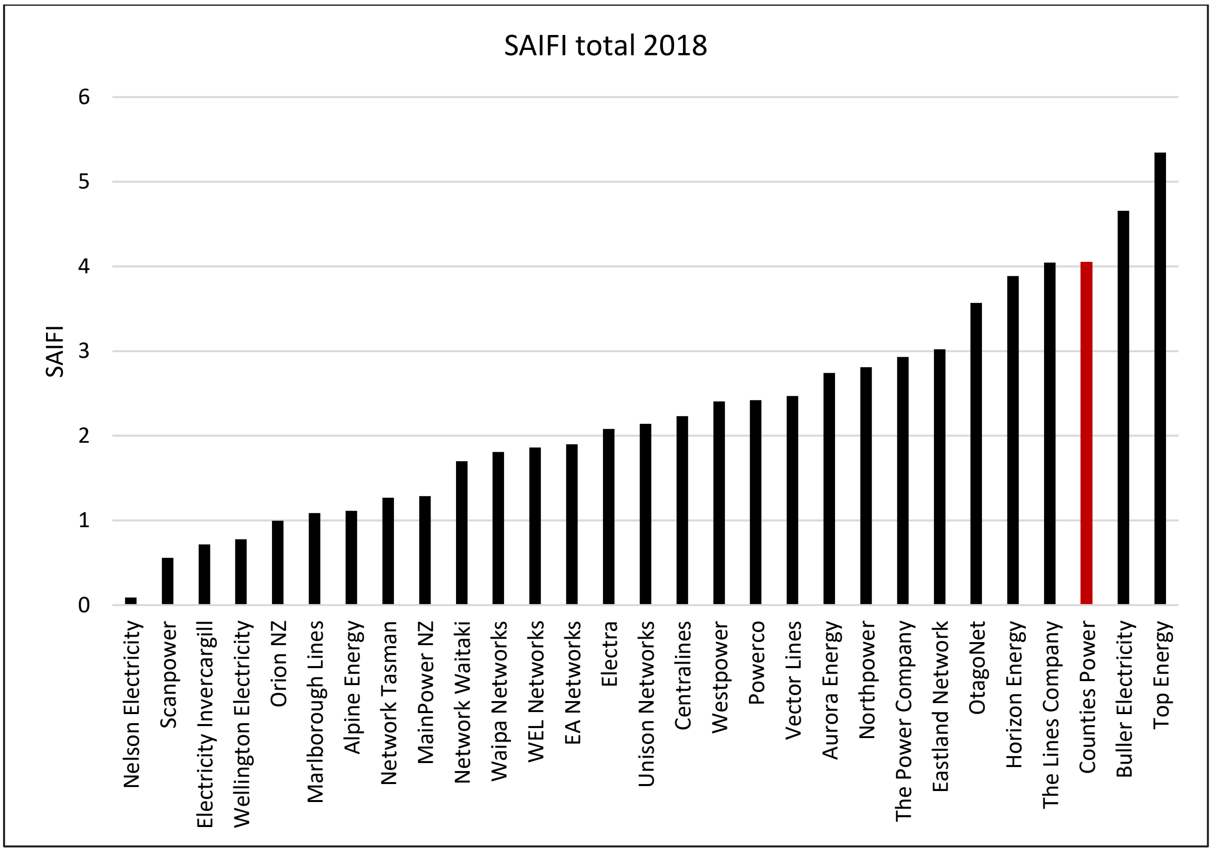


Figure 3-6 Normalised network SAIFI utilising ID normalisation – Industry Comparison 2018

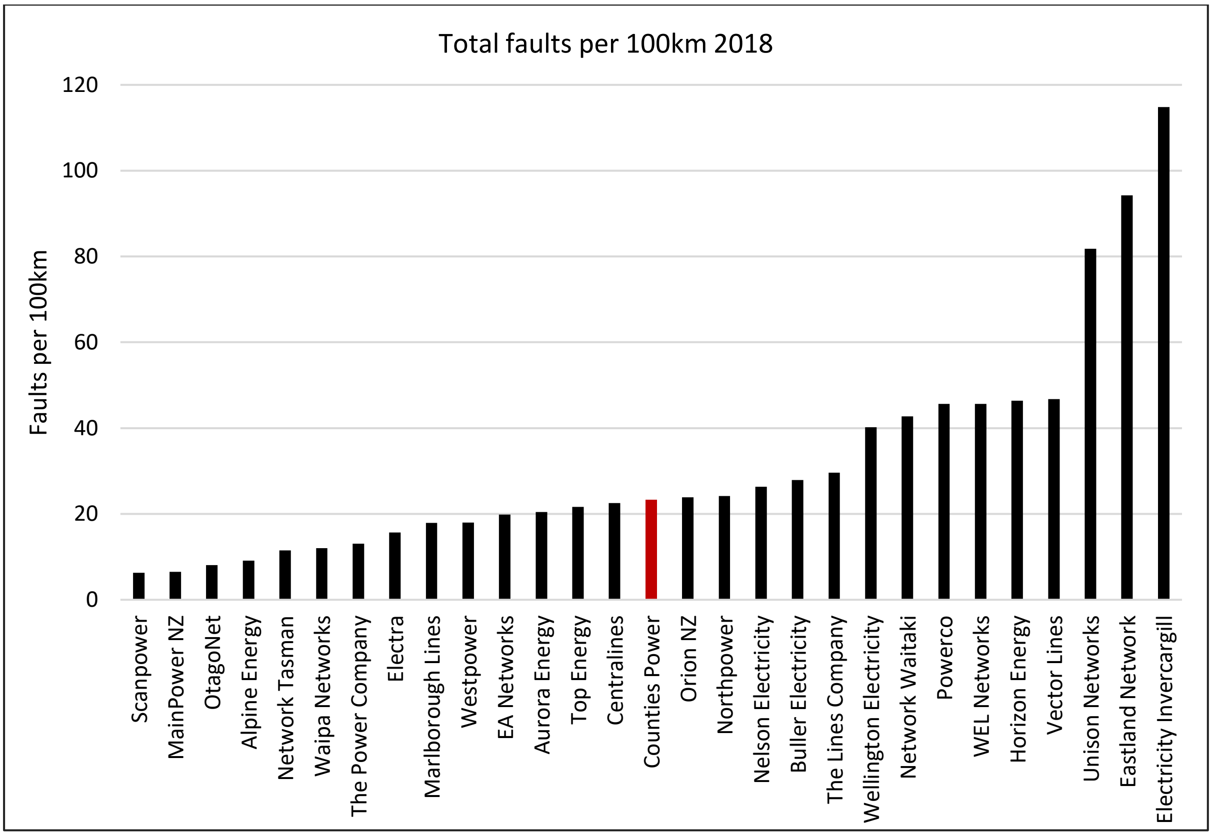


Figure 3-7 Total Faults per 100km – Industry Comparison 2018

3.4.3 Network performance analysis

Network performance, as measured by SAIDI and SAIFI, is unfavourable both to our own targets, and when compared to industry averages. SAIDI and SAIFI are high relative to similar networks and reflect the higher feeder customer density resulting from our 22kV feeders and notable increases in overhead equipment failure, debris, vehicle damage and 'no fault found' incidents. This can be seen in Figure 3-8, where the number of faults by type have shown an upward trend from 2016 to 2018. Positive downward trends have been noted with network performance measures of SAIDI and SAIFI for the current regulatory year 2018/19 (YTD), however at the time of writing this AMP, the full year performance is not known and this position may change at year end.

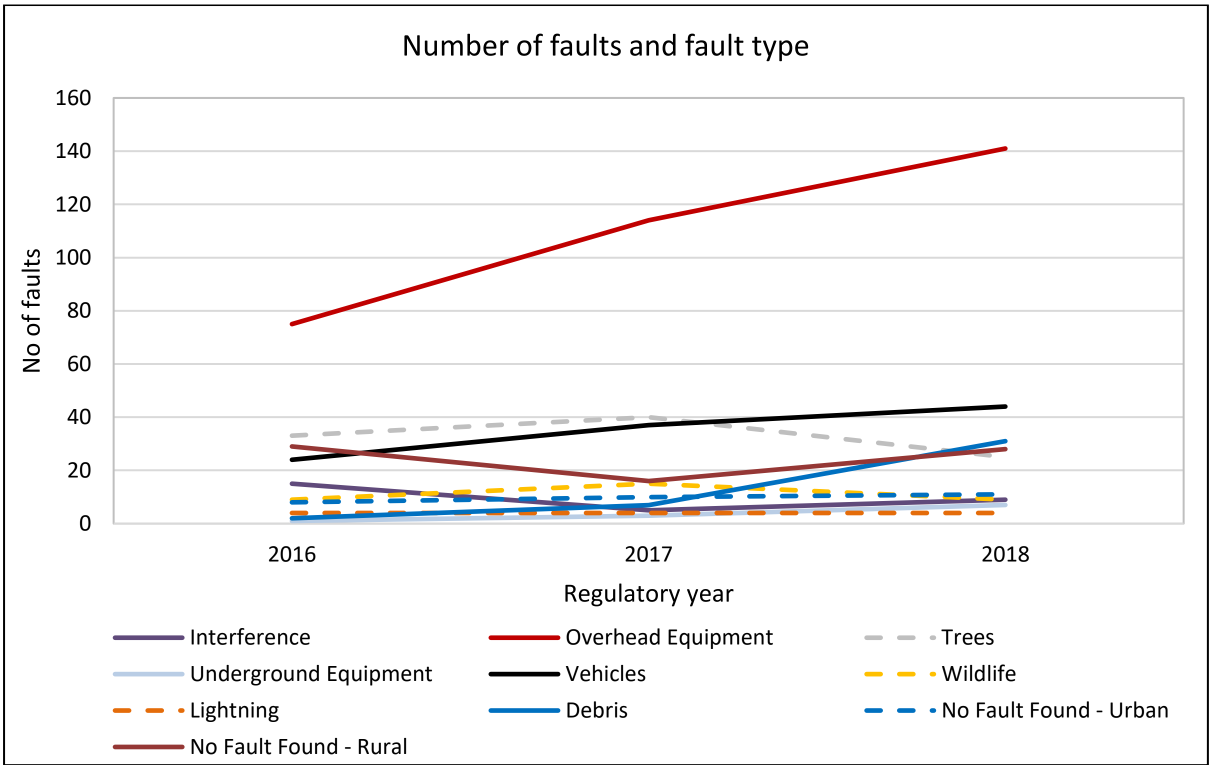


Figure 3-8 Number of faults and fault type

Overhead equipment faults have been largely related to end of life conductor failure in both storm and non-storm situations, broken or defective overhead switchgear, and component failure such as insulators, binders and fuses. To address these issues, increased levels of asset replacement expenditure is planned for short to medium term of this plan. Details are included in Section 5.

When considering the number of faults by type, the SAIDI impact of those faults, as shown in Figure 3-9 Unplanned SAIDI by Fault Cause, shows large contributions from overhead equipment, vehicle damage, debris and 'no fault found' events. The impact of vehicle damage is harder to control, and investigation has shown little commonality to vehicle damage sites, although where possible equipment is located to avoid future vehicle damage. Overhead equipment contributes to both the number of faults, as well as the individual impact due to the nature of some fault types. Some equipment failures are difficult to identify in fault patrols, and new technology has been deployed to narrow down faulted areas and identify failing components to reduce the overall outage time.

Vegetation remains a challenge for the business as landowners often do not undertake their obligations under the Tree Regulations, or in many cases experienced, the vegetation is blown debris or trees falling from outside the zone enforceable by the Tree Regulations.

The increased level of automation on the network allows faster isolation and partial restoration of supply, as well as targeted maintenance and asset replacement in high impact areas. The impact from 'no fault found' events is still high largely due to changes in manual reclose practises implemented by Counties Power in 2016. This is compounded for a 'no fault found' event on a high density urban feeder, which take longer to patrol prior to any manual reclosing. This decision to change manual reclose practises was made on the basis of public safety, particularly in a lines down event, but has led to an increased SAIDI contribution.

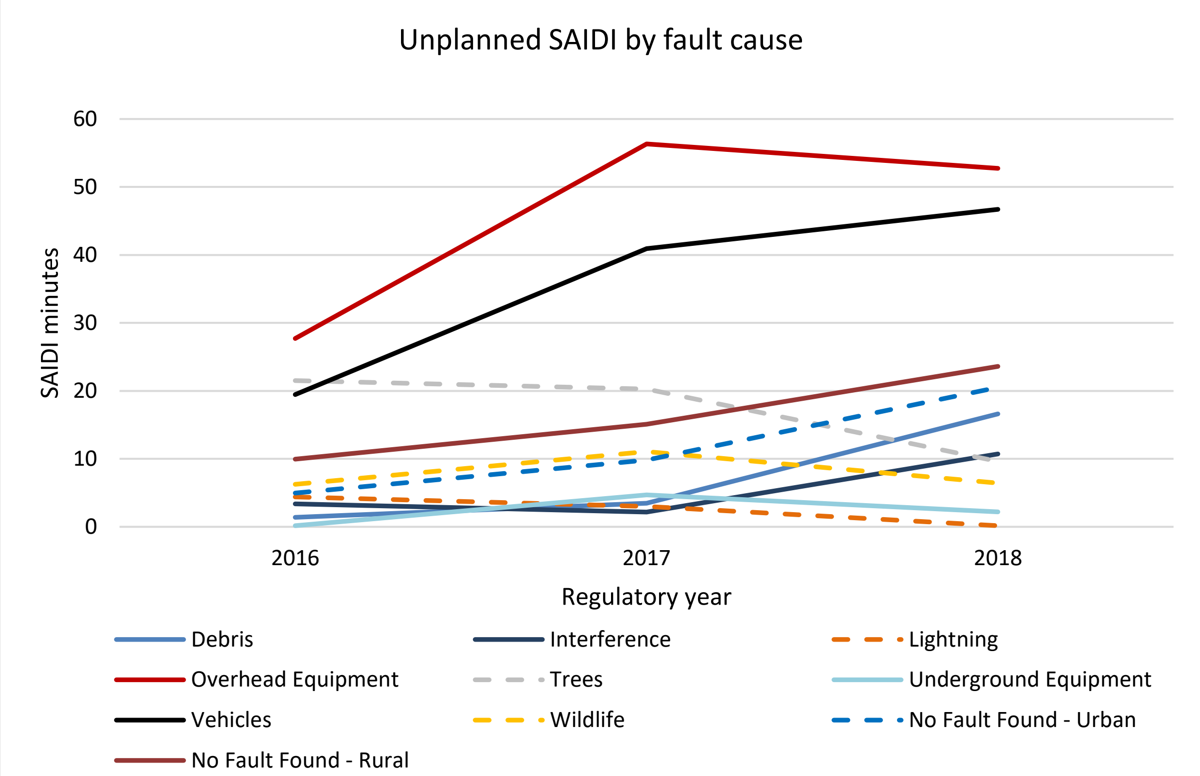


Figure 3-9 Unplanned SAIDI by Fault Cause

In order to provide appropriate levels of network performance, we have the following initiatives in place:

- Vegetation management – a proactive programme of vegetation surveys and tree trimming to ensure supply is not interrupted by trees coming into contact with overhead lines;
- A focus on worst performing feeders – identifying which feeders have the greatest number of outages, as well as those that have high SAIDI and SAIFI impacts, and undertaking remedial works to ensure the assets on these feeders perform as expected[13];

[13] Part of a 3-year rolling performance improvement plan focusing of top 10 worst performing feeders.

- Post fault analysis of all events that cause more than 20,000 customer-minutes to be lost, or affect a major customer, to identify the root cause of the fault and to implement corrective actions to prevent reoccurrence;
- Car vs pole post incident investigation and reporting, and follow up actions with internal and external stakeholders such as Police and local roading authorities;
- Updated security criteria for the maximum allowable connections per feeder to reduce the impact of faults. This will lead to investment to split feeders with high customers numbers and is further detailed in Section 6;
- Increased maintenance and replacement of overhead components in worst performing areas as detailed in Section 5; and
- Deployment of new tools and technology to identify fault locations to enable quicker restoration of consumers in affected sections of the network.

3.5 Service level: Customer service

3.5.1 Objectives

- Our customers and consumers are aware of who we are and what we do;
- Customer feedback is easy to give and it can be given across multiple channels;
- Customers and consumers know we will act on their feedback and requests, and they value the services we offer; and
- We aim to deliver our services (including the delivery of electricity) at the levels sought by our customers.

3.5.2 Initiatives

- Ensuring customer feedback is integrated into both our asset management planning process, and AMP;
- Enhanced communication channels to customers for planned and unplanned power outages, including implementation of real-time messaging service for unplanned outages and updated self-service web application;
- Process reviews and continuous improvement of our service offerings to make it more efficient and easier to serve our customers;
- Establish and start to measure the delivery of our services against time, accuracy and satisfaction parameters;
- Surveys of customers, seeking feedback on our service, our price and reliability;
- Achieve 100% compliance with Utilities Disputes (formerly the Electricity and Gas Complaints Commission - EGCC) scheme; and
- Seek and record customer contact information so notifications can be sent out in the event of an unplanned outage.

3.5.3 Targets

- Overall customer satisfaction with our services, price and reliability;
- Response times (acknowledgement) of letters and electronic communications from customers and consumers;
- Positive customer and consumer feedback on services we provide;
- Complaint handling meets or exceeds Utilities Disputes (and our own) requirements.

Description	Target
Service request – such as providing a new supply for new reticulation; permitting a high load or processing a Distributed Generation approval	On the date agreed with the Customer (or their Retailer) for that service
Voltage Complaint	Acknowledge complaint within 5 Business Days after receipt of the complaint Advise outcome of investigations and nature and timing of intended remedial action (if required) within 10 Business Days after receipt of the complaint
Complaint Handling	Acknowledge complaints within 2 working days and closure within 20 working days
Service response	Answer an average 80% of calls within 20 seconds (force majeure events excluded) and acknowledge or resolve customer-driven service requests via email by the next working day

3.6 Service level: Economic efficiency

3.6.1 Objectives

- Effectively and efficiently manage the network to have a low cost to serve;
- Reduce losses on network; and
- Ensure high utilisation of assets (load factor).

3.6.2 Initiatives

- Continuous improvement in works delivery model and processes to reduce costs;
- Investigate new technology options for reduced 'whole of life costs';
- Actively manage capacity and asset utilisation; and
- Utilise distribution voltages to reduce technical losses where economic to do so.

3.6.3 Targets

Cost to serve – operating expenditure

To deliver on our vision of having cost effective supply of electricity to our consumers, it is important we have efficient operating costs. We measure operating cost per consumer, and by system length, and aim to be at or below the industry average and ensure the asset management and business operating decisions we make do not drive unnecessary cost into the business.

Our performance and targets are shown in the table below.

Operating Cost per ICP	2016	2017	2018	2019+ Target
Counties Power	$291	$321	$309	$295
Industry Average	$352	$367	$390	

Operating Cost per KM	2016	2017	2018	2019+ Target
Counties Power	$3,631	$4,042	$3,985	$3,600
Industry Average	$3,583	$3,780	$3,970	

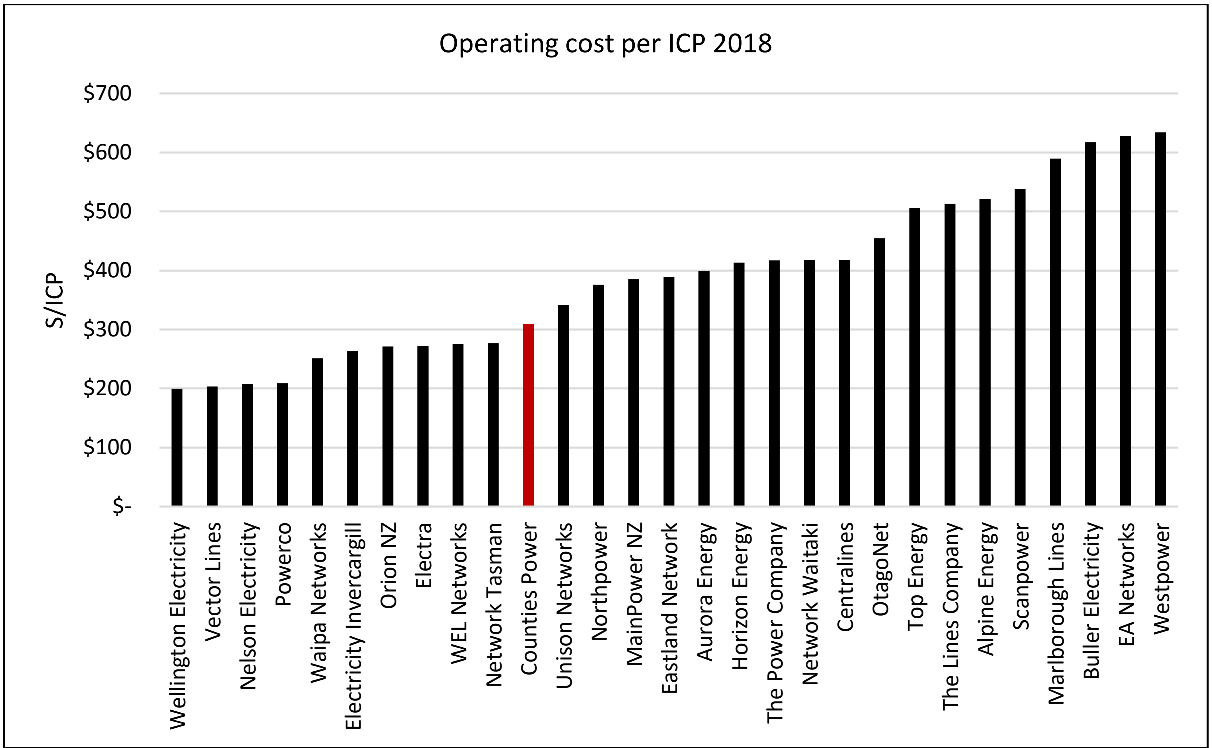


Figure 3-6 Operating Cost per ICP – Industry Comparison 2018

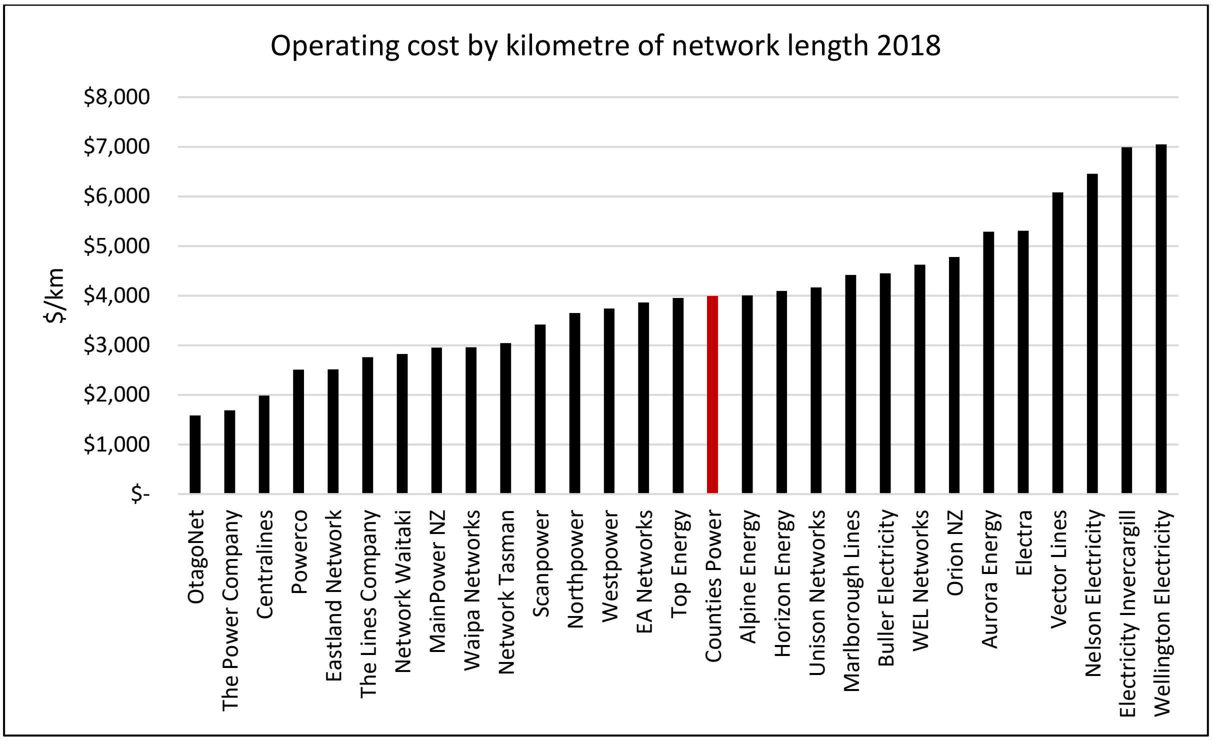


Figure 3-71 Operating Cost per km of Network Length – Industry Comparison 2018

Network losses

We aim to keep our losses at or below the industry average. As we had predominantly rural network with moderate consumer density, our electricity losses will generally be high. Losses have been kept close to the industry average through the use of higher operating voltages, and the network architecture we have implemented. Our deployment of smart meters, and consequential installation audits have reduced technical and non-technical 'unaccounted for energy' on the network over the past three years.

Our performance and targets are shown in the table below.

	2016	**2017**	**2018**	**2019+ Target**
Counties Power	4.5%	4.4%	4.7%	less than 4.5 %
Industry Average	6.0%	5.9%	5.6%	

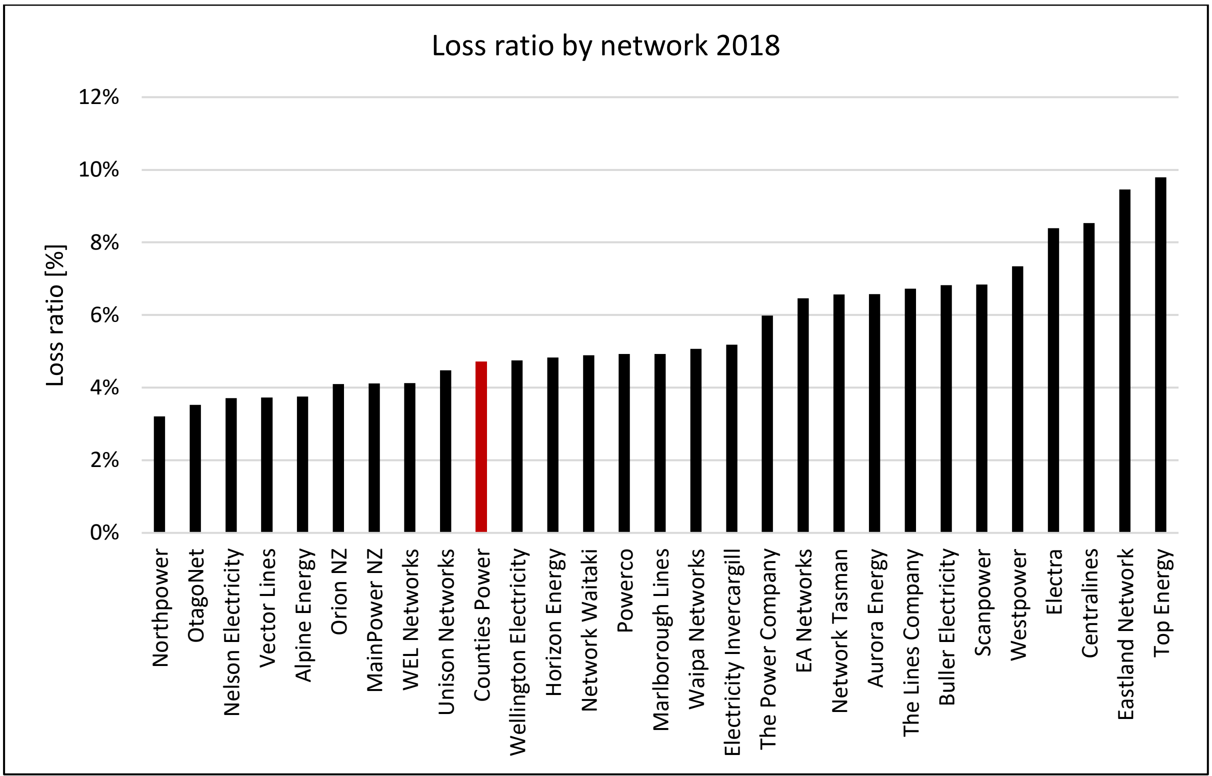


Figure 3-82 Loss Ratios – Industry Comparison 2018

Network utilisation

Network Utilisation is another important aspect of operating an economically efficient electricity network, and ensuring that our distribution network has been constructed in a way that meets consumer demand, but does not have too much excess capacity built in. The Load Factor is an important measure of utilisation as it compares the installed transformer capacity to the demand at peak times.

Our performance and targets are shown in the table below.

	2016	2017	2018	2019+ Target
Counties Power	57.8%	57.4%	57.9%	60.0%
Industry Average	61.0%	60.3%	59.0%	

Due to the high level of growth being experienced on the network, we are undertaking a large number of network extensions and multi stage subdivision reticulation projects which are creating headroom of installed distribution capacity ahead of the uptake in demand. We expect this to change in the coming years, and our utilisation figures to increase as new loads are connected to existing transformers.

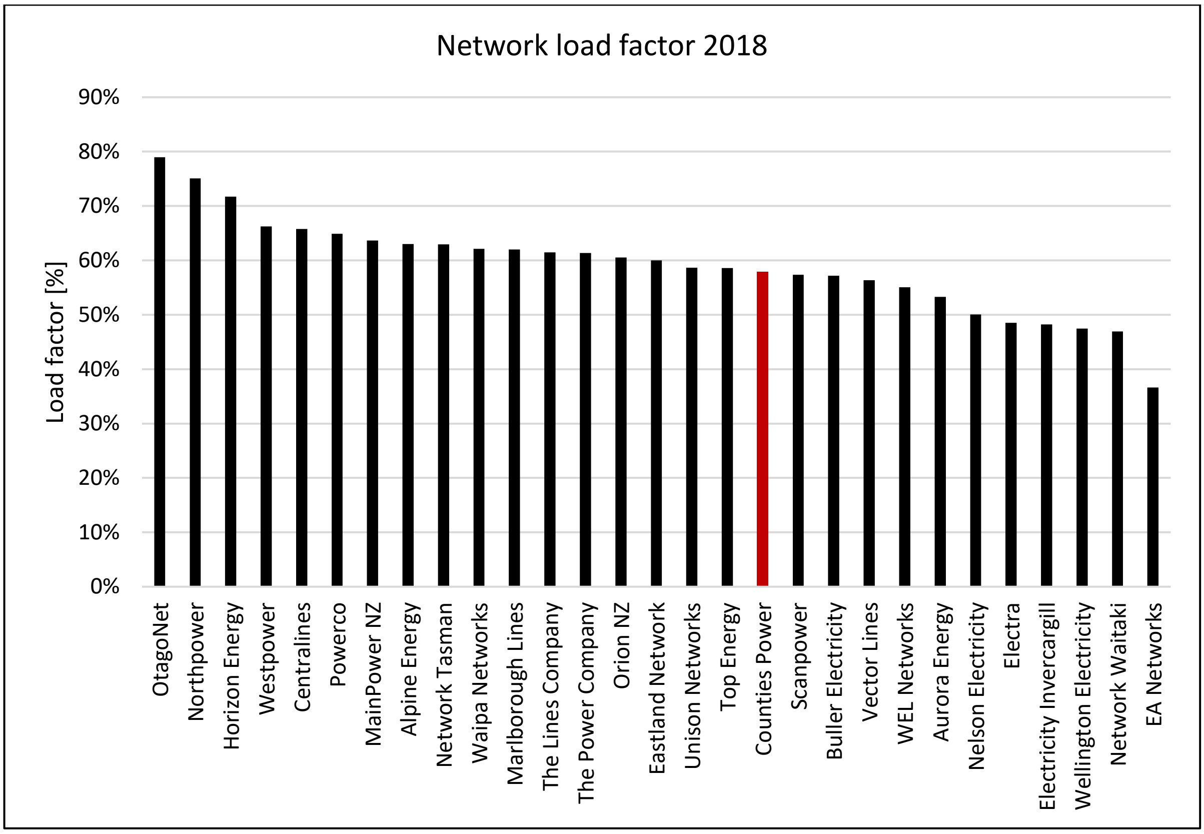


Figure 3-13 Load Factor – Industry Comparison 2018

4 Approach to Asset Management

4.1 Asset Management framework

4.1.1 Framework overview

Figure 4-1 below shows the high level Asset Management framework for Counties Power. This has been developed to allow for aligning ourselves with the principles of the ISO 55000 framework.

Figure 4-1 Asset Management Framework

4.1.2 Asset Management policy

Our Asset Management Policy links our Asset Management approach to our corporate objectives and details the Objectives, the Accountabilities and the Implementation considerations.

Our Asset Management Policy Objective is to “optimise the whole of life costs and the performance of the network to sustainably deliver safe, reliable and cost-effective supply to our consumers”.

4.1.3 Asset Management strategies

We have developed asset management strategies to deliver the requirements of the Asset Management Policy, these cover maintenance, replacement, and network development.

Each of these strategies informs this Asset Management Plan and results in proposed programmes of work – comprising operational expenditure and capital investment – which are detailed in Section 5, 6, and 7 of this plan.

Maintenance strategies

Maintenance comprises asset inspection, measurement, recording and assessment of condition and undertaking required corrective or preventative action to minimise risk and/or maximise performance. In the course of normal business some assets fail in service, often influenced by external factors such as trees, motor vehicles, wildlife, or extreme weather. We have to repair or replace those assets reactively.

Maintenance is required to meet our objectives of providing a reliable service that our consumers value, our obligations under our Public Safety Management System, to meet the requirements of the *Electricity (Safety) Regulations 2010* and to ensure we meet good industry practice.

Our maintenance programme consists of three categories of maintenance activity.

- **Preventative maintenance** – routine inspection, testing and servicing to ensure our assets are safe, free from defects and meet their service expectations. We also use the inspection process to undertake condition assessment to forecast when the asset will have to be refurbished or replaced. We include vegetation management as a form of preventative maintenance;
- **Corrective maintenance** – scheduled repairs to assets following inspection or testing, to address known defects, based on the risk they present; and
- **Reactive maintenance** – unplanned repairs or replacement of assets once a defect or failure has been identified, or where they present an immediate risk to safety or the network.

A key part of our maintenance strategies is to assess the benefits of major repair work against outright replacement or retirement of assets. Although the cost of replacement can be many orders of magnitude greater than a repair, we consider the 'whole of life' cost of the asset when contemplating repairs to assets nearing the end of their economic life.

We undertake targeted maintenance in some areas where network performance is poor, or the consequence of failure is extreme, and categorise 'Worst Performing Feeders' to address reoccurring issues and improve network performance.

Replacement strategies

As we are a rapidly growing network, a number of areas of the network have been constructed or rebuilt over the past 20 years which means some parts of our network are relatively new. Other parts of the network, particularly the older 11kV network in the southern and western areas, are at end of life and are beginning to experience increasing rates of failure, particularly at component level, as well as systemic issues with certain types of conductors. We forecast that a higher level of renewal expenditure will be required over the planning period to address safety, condition and performance risks with this older equipment.

Major substation plant is of high value, has a significant consequence associated with failure, and can present a serious risk to safety, the network, and the environment if poorly managed. We have preventative and corrective maintenance programmes to ensure these assets perform as expected and to ensure we understand their condition to allow us to plan repair and replacement activities. We base replacement of major assets on a detailed condition assessment, as well as an assessment of the risk of failure. Options analysis is undertaken where investment is significant or in an area where major changes in demand forecast are being projected.

Many of our major substation assets are approaching the end of their economic service life just as capacity and security constraints are becoming binding. This allows the assets to be replaced at the optimal time to maximise their service life by moving towards condition based replacement and be upgraded to meet new capacity requirements at the time it is required. More details of this can be found in Section 6 Network Development Planning.

Distribution assets are generally in the public domain and can present a risk to public safety. We inspect these assets to identify defects and undertake condition assessment, analyse failure rates and causes to forecast when replacement will be required. Our objective is to replace these assets based on condition before they fail or present an unacceptable risk.

Some asset classes have a lower risk to safety and network performance and have a low consequence of failure. These can be managed with a run-to-failure strategy.

In some cases, where the asset is at end of life and is no longer required or has been superseded, it may be retired from service without replacement.

A detailed description of our replacement programmes is covered in Section 5 Renewals and Maintenance.

Development strategies

As demand on our network grows we have to ensure it is able to meet our consumer's requirements for capacity, security and reliability.

We have developed security and planning criteria and assess the network against these for the reasonable growth forecast. This results in the identification of constraints and timeframes for investment. Our strategy is to ensure that the development options we select do not lead to over investment (too much), premature investment (too soon), or lead to a high risk of asset stranding. We also aim to get as much renewal benefit as possible when upgrading or replacing assets due to growth and avoid the early write-off of assets before the end of their economic service life.

Future projects include specific works to work towards improvement of our network performance as defined by SAIDI and SAIFI to reflect customer and wider expectations of service delivery.

Details of these network development plans are covered in Section 6 Network Development Planning.

Integration of strategies

Whilst each of the above three strategies identify actions that are required on the network to ensure that all expenditure is optimised, proposals from each driver are examined against the other two drivers to check that the proposed works are integrated.

A process is followed which compiles a detailed integrated Network Development Plan for all types of work which is reviewed to ensure works are fully integrated. For example, if a replacement strategy initiated project on a line has been identified this is checked against development strategy projects to ensure that if reinforcement is planned for the near future in this vicinity the final project reflects all drivers and requirements.

At a detailed level the formal integration of project lists is carried out on an annual basis and any proposed change or additional work (e.g. triggered by an inspection) that arises during the year is reviewed at that time.

4.2 Investment planning

Our network investment process consists of a sequence of decision making steps, used to ensure we make the correct investment decisions and have adequately considered alternatives. A high-level overview of this process is shown below.

The key steps in our investment planning process for network initiated projects are:

1. **Identification of the need** – the need for investment arises from routine business cycle activities such as the network planning process which identifies constraints on the system and the maintenance process which includes asset condition surveys, network fault and performance data. These processes produce outputs of a list of issues which may require investment.
2. **Prioritisation of the need** – once the Need has been identified, it is prioritised by risk (including safety, security, reliability, environmental, and regulatory) and the timing of when the issue requires resolution
3. **Assess options** – a long list of possible solutions is developed, with a high level order of cost and assessment of benefits. Benefits will include all aspects including those directly seen by our customers (such as improved SAIDI and SAIFI performance) as well as wider benefits from improved network resilience. From this a short list of preferred solutions is selected, based on the cost, the benefits they provide, and the alignment with our strategic goals.
4. **Check against other works –** As noted there are various drivers for investment (growth, maintenance, refurbishment, performance improvement), thus projects being considered from one driver are checked for overlap with other projects to optimise planned expenditure.

5. **Select a solution** – once the short list of options has been assessed, a preferred solution is selected based on delivering the greatest benefit, which is then scoped and priced to a detailed level to allow a full business case to be developed.
6. **Approvals to proceed** – the business case outlining the preferred solution is presented for the appropriate level of management or Board approval.
7. **Implementation of the solution** – once approved, the solution enters the design and delivery phase, where the detailed design is created, the scope of works finalised, and it is handed to Field Operations to deliver the solution.

For customer initiated projects such as network extensions and subdivision reticulation, the investment decision making process is simplified and a solution is identified to meet the customer's requirement for capacity and security. The timing of these investments is to suit the customer and is not discretionary.

A summary of our processes for investment planning are shown in Figure 4-2 and Figure 4-3.

4.2.1 Investment planning process – renewal and replacement

Our process for renewal and replacement investment is shown in the diagram below. Key inputs to this process are Asset Condition Surveys, Known Type Issues and Performance Issues. These are all prioritised by the risk the asset presents, considering public and employee safety, network security and reliability, regulatory requirements and environmental effects.

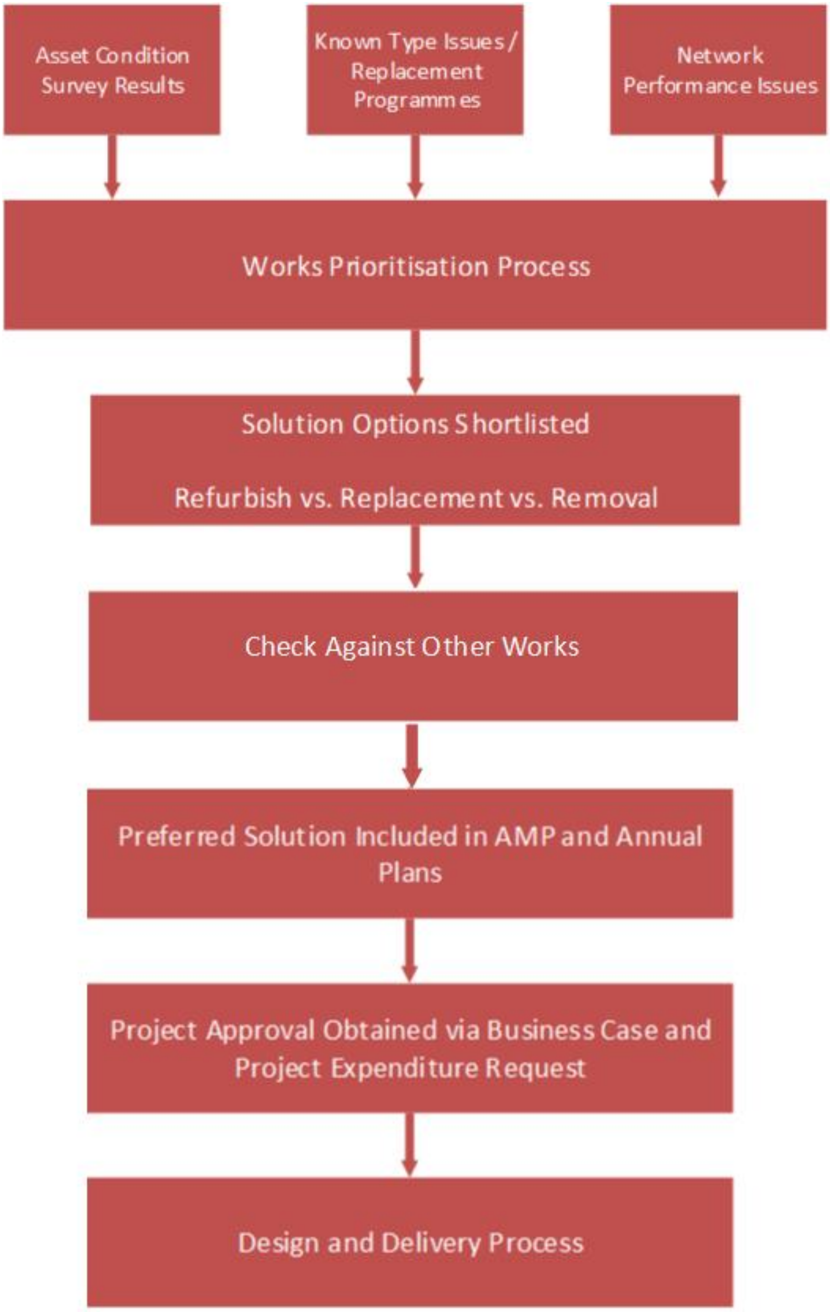


Figure 4-2 Renewal and replacement investment process

4.2.2 Investment planning process – Network Development

Our process for network development investments is shown in the diagram below. Key inputs to this process are the load forecast, the network model and system capability, and the security and planning criteria. When considered together, these identify constraints on the network which will drive invesment. Full details of this process are provided in Section 6 Network Development Planning.

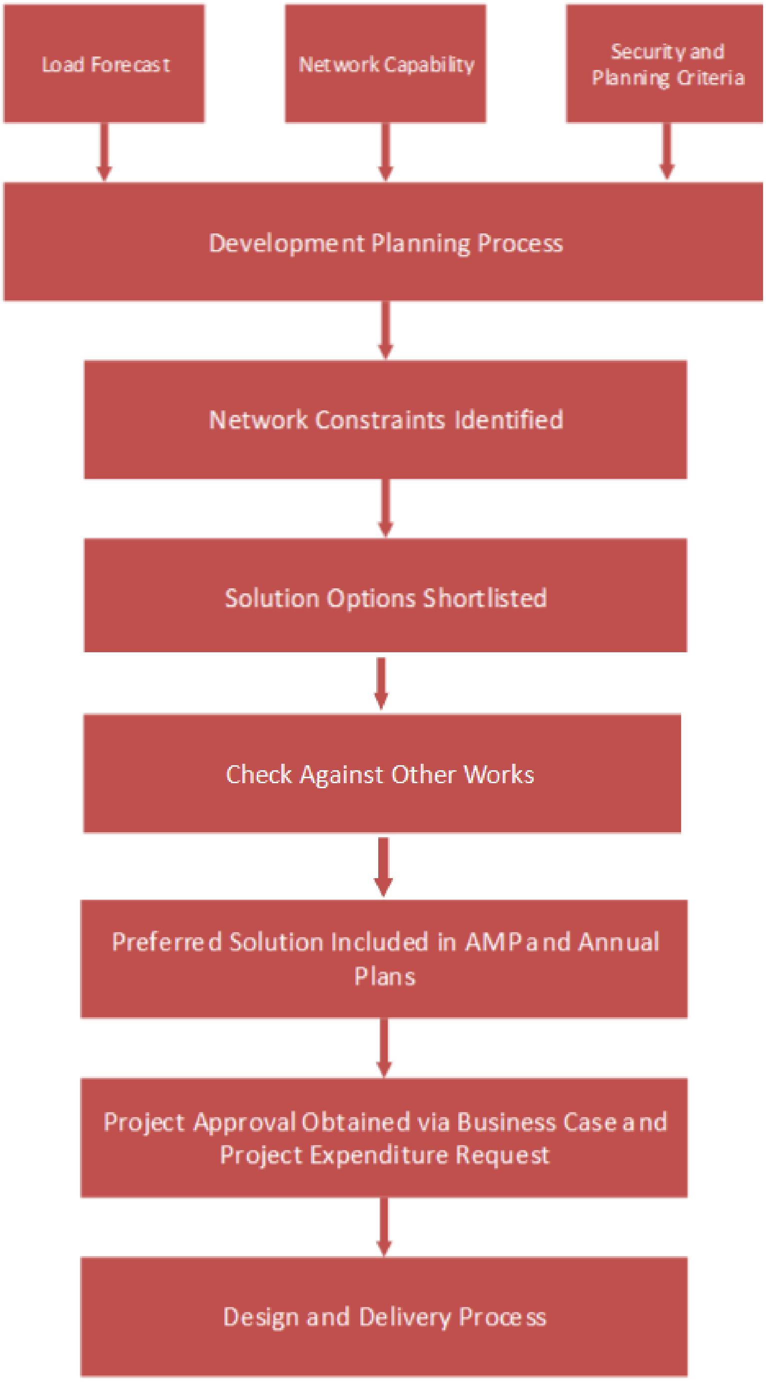


Figure 4-3 Network development investment process

4.2.3 Consideration of network alternatives

Network alternatives (sometimes referred to as non-network solutions) are considered in the options analysis to address a network constraint, particularly a capacity or voltage constraint.

We then consider if network alternatives are feasible such as demand side management, localised storage or generation, and other assets which can be installed to defer the need for investment by reducing the peak demand or supporting the voltage along a feeder.

Where the investment need is driven by poor condition of assets presenting a safety risk, a network alternative is not normally suitable, and investment in replacement network components is required, however consideration is given to the size and configuration of these to determine if the network can be optimised in any way.

Further details around our assessment and selection of Network Alternatives is covered in Section 6 Network Development Planning.

4.2.4 Energy efficiency considerations

As part of our network planning process, we make the following considerations for energy efficiency.

- **Voltage and loading** – we select appropriate operating voltages and operate the network in a configuration that minimises electrical losses;
- **Energy efficient equipment** - we ensure that all new equipment, in particular transformers, comply with the required IEC and AS standards for energy efficiency, in particular the Minimum Energy Performance Standard;
- **Design options** - for network reinforcement we review the impact on efficiency from a network losses viewpoint and this is considered in the preferred option selection process; and
- **Metering** – we ensure our metering equipment is calibrated and compliant with the Code to reduce the 'unaccounted for' energy lost on the system.

4.3 Asset Management information and systems

4.3.1 Asset Management systems

There are a number of key systems used in the asset management process, as well as part of our wider business operation. The key systems are listed below with a brief description of the role they play. Some minor systems have not been detailed here.

Geographic Information System (GIS) – Smallworld Electric Office

We have recently upgraded to GE Smallworld Electric Office to record all our geospatial information relating to network assets, including location, physical and electrical attributes. This platform is also used to record some maintenance attributes relating to the assets, and enables the business to:

- View geospatial data on the web without needing a full software licence;
- Have a common platform to view projects across the network for improved coordination; and
- Geospatial Analysis (GSA) tool to deliver analysis and reporting.

As part of the implementation of this upgrade, a significant amount of data cleansing and connectivity improvements were undertaken. GIS data quality improvements are a focus area in the coming years.

Supervisory Control and Data Acquisition (SCADA) – iPower

Our GE iPower SCADA system is used for real time operations of the high voltage network and provides telemetry and remote control of substation and automated field equipment such as ring main units and overhead switchgear. It is used for network switching in planned and unplanned (fault) situations and provides a representation of the network and all the control points such as switches and ring main units. It has the capability to record event logs and measurement data for future analysis.

This system also contains the load management functionality we use to manage system peak demands and to operate our load control (ripple) plants.

Microsoft Dynamics NAV

We use Microsoft Dynamics NAV as an enterprise resource planning system and primary system of record, chiefly for financial management and accounting, purchasing, but also for customer service, project management activities such as quoting and estimating, and works management.

This system has been customised to provide a number of Asset Management functions including:

- Faults and Outage Recording and Reporting;
- ICP Management and Billing;
- Asset Survey Records; and
- Vegetation Management Records.

Field computing tools

We have developed a range of in-house field tools based on the Google Android platform. These are used as part of our despatch process, as well as for recording job information in the field, and capturing the results of asset surveys. This system has linkages to GIS and NAV.

SharePoint Intranet sites

The business has a SharePoint based electronic document management system (EDMS) which provides a number of functions to the business, primarily as an intranet containing a range of corporate information and providing a platform for two important Asset Management requirements:

- Public Safety Management System – for recording information on all PSMS activities and reported incidents; and
- Quality Management System – for managing all controlled documents such as policies and standards.

DIgSILENT Powerfactory

Powerfactory is used as the main network planning tool for power flow analysis and network simulation. We use it for undertaking systems studies for large scale new connections, assessing network loads and identifying network constraints, and for assessing network performance and operational scenarios. We have a complete network model represented within Powerfactory.

AutoCAD

All of our design work is undertaken in AutoCAD including substation electrical designs, network projects and subdivision reticulation plans. We also create standard drawings in AutoCAD for common construction assemblies. Our network operational diagrams are also maintained in CAD format.

Smart meter and outage management system - INDI

Counties Power manages customer outages (planned and unplanned) using our in-house smart meter and outage management system. This system provides near real time feedback for loss of power at individual customer level enabling us to ensure rapid response and proactive outbound communication during power outages. In addition, we use smart meter demand and consumption data for electrical designs and network projects.

4.3.2 Asset Management information

To support our asset management processes, we use the following information, some of which is held electronically, and some is held in hard copy. Our expectation is that all asset management information obtained going forward will exist in electronic format in centralised repositories.

Examples of our asset management information includes:

- **Controlled Documents** - as part of our Quality Management System (QMS), these include all Polices, Standards and Procedures;
- **Standard Drawings** – these detail how we build our network, and include standard underground and overhead assemblies used by field crews working on our assets;
- **Network Diagrams** – this information is contained in both AutoCAD drawings, as well as in the GIS system. These are used to plan and operate the network;
- **Test and Inspection Records** – outcomes of these activities are stored for future reference and for regulatory compliance;
- **Fault Records** – following planned and unplanned outages on the HV network (as indicated by SCADA events or customer calls), fault records are created in the NAV system indicating duration, cause and number of customers affected. These are used for calculating our SAIDI and SAIFI figures for regulatory reporting, as well as analysis of network performance trends; and
- **Legacy Information** – we have a range of information contained in hard copy format, particularly older test and inspection records, equipment manuals and technical documentation. Some information has been digitised, however much of it remains in hard copy and there is little benefit in digitising it.

Through our business process, we identify the information we require to make decisions relating to our network, and where necessary introduce new processes to capture this, and identify where systems need to be updated to accommodate this.

As new standards and processes are developed, these are processed through our QMS and socialised with relevant stakeholders through training sessions, toolbox meetings, team meetings and electronic communications such as email.

We have identified opportunities for improvement on how we manage our geospatial data. With the implementation of our new GIS system, we will utilise the electrical and quality checking tools available to verify data integrity with focus on urban areas in 2019. In addition, our as-building and data capturing processes will be updated to reflect the requirements of the new system.

4.4 Works delivery processes

4.4.1 Key works processes

An outcome of the Asset Planning process is a range of work that comprises the annual work plan. Once the annual budgets are approved, individual projects and programmes of work gain approval by way of a business case or programme justification. This section describes the key works processes in delivering the plan.

Network projects

Network projects cover a range of work from system growth and capacity projects, through to asset replacement and renewal programmes.

Once a project has been included in the annual plan, and expenditure approval received from the appropriate authority holder, the work is initiated by either the Asset Engineering team (for renewal projects) or Network Development team (for growth/development projects) and a design and specification is created (or a basic work pack for minor jobs) by a Design Engineer within those teams. This work is agreed with the Field Operations group, a Works Manager is allocated, the work is scheduled through a mix of internal and prequalified external resources, and the project enters the construction phase.

Once construction is completed the work is audited and accepted by the responsible Design Engineer and the Network Control team, and the assets enter their operational phase.

Customer projects

Customer projects include new connections to existing network, network extensions or new subdivision reticulation, or other customer initiated work such as street lighting connections, asset relocations or capacity upgrades.

Customer projects are initiated with requests coming through the Connections team, or directly to a Customer Projects Engineer in some cases (larger subdivisions). The customer requirements are identified, a concept and budget price is presented for the customer and following acceptance of this a detailed design is created and quoted, and an offer is made. When the customer accepts with payment the work is passed to the Field Operations group in the same way a network project is managed.

Preventative Maintenance planning

Preventative maintenance is the programme of routine inspections, testing and servicing of network assets to ensure they are performing as expected with regard to public and employee safety, network reliability, that they are free of defects, and to survey their condition to determine when end of life replacement is required.

The type of activity, and the frequency that it is undertaken, is determined by regulatory requirements, known historic performance, manufacturer's recommendations and good industry practice. We develop maintenance standards for each asset class and these are used to develop the overall Preventative Maintenance Plan.

The Asset Management group develops the annual preventative maintenance plan in conjunction with Field Operations, who then deliver the programme over the course of the year.

Corrective Maintenance planning process

Corrective maintenance addresses network defects arising from preventative maintenance surveys, replacement of components following network faults where supply has been restored but further work is required, or to address other network requirements such as dismantling of old assets or refurbishment of equipment.

Corrective maintenance is prioritised based on the following criteria:

- Public and Staff Safety Risk;
- Location of the affected equipment;
- Impact on Network Operations;
- Type and Severity of Defect; and
- Type and Age of Equipment.

The Corrective maintenance programme is developed by the Asset Management group in conjunction with the Field Operations group and the individual work packages are scoped up along with a description of the required work. During the course of the year the programme may be reprioritised to address higher risk defects on the network.

Reactive Maintenance process

Our reactive maintenance process handles the situations where network assets have failed in service, or been damaged by external influences, causing an outage or presenting an immediate hazard.

Outages on the Low Voltage system typically result in a customer calling into our Customer Service team, or to our call centre, or are logged using our consumer web application. A service order is created and dispatched to a duty fault crew who then attend to the issue.

Outages on the High Voltage system are notified to a Network Controller through the SCADA system, where a substation circuit breaker or field device such as a recloser has operated. In this situation fault crews are dispatched to attend to the issue by the Network Control team, and undertake the necessary network switching and isolation to restore customers, and complete repairs to the network.

Immediate hazards can be identified by our staff or are reported by members of the public through our Customer Service team. Similar to the Low Voltage outage process, a fault crew is dispatched to attend to the issue.

Vegetation Management process

We undertake vegetation management to ensure safety around our network and that network performance meets expectations. Our vegetation management is undertaken in accordance with the *Electricity (Hazards from Trees) Regulations 2003*.

We have a vegetation management team in our Field Operations group which oversees and delivers the vegetation management programme, including undertaking tree surveys, tree owner liaison and undertaking much of the field work. In some cases, external subcontractors are used.

Once a tree has been identified as presenting a hazard to the line, or is within the limit zones, a notice will be issued to the tree owner. First cuts are undertaken by us, and second and subsequent cuts are the responsibility of the tree owner.

The vegetation management strategy is set by the Asset Management group, with a focus on the subtransmission network, backbone distribution feeders, and historically poor performing areas.

Public Safety Services process

In addition to providing fault response and routine maintenance on the network, we provide a number of public safety services to ensure those working around our network do not come to harm or cause damage to our assets, including:

- **Close Approach Consents** – where third parties wish to operate machinery or undertake other activities within 4.0m of our network they need to be aware of the hazards and have our permission in writing in accordance with ECP34;
- **High Load Permits** – where transport operators wish to move oversized objects, typically houses, along routes which have overhead lines. In some cases, we provide an escort to assist them and reduce the likelihood of harm to people or damage to the network;
- **Plans and Markouts** – we provide plans of our network, and can undertake onsite locates or markouts to show where our buried services are; and
- **Safety Disconnections** – the disconnection of consumer supplies to enable them to undertake work on their property without the hazard of live electricity.

Members of the public or contractors can request these services from Counties Power. These requests are initially handled by our Customer Service team, and the requests are fulfilled by the Network Control or Field Operations teams depending upon the nature of work required.

4.4.2 Field delivery capability

The majority of field work is managed and delivered internally by Counties Power through our Field Operations group.

We have internal capability to undertake fault response, routine network maintenance, construction of overhead and underground networks, substation electrical work, electrical inspections and meter installations, as well as vegetation management.

We outsource some types of work where we do not have the capability and/or the capacity, for example where:

- The tasks require a specialist skill which Counties Power staff do not have, and volume of work does not justify having those skills internally – for example some protection and communications work, fibre optic splicing, specialist substation work such as major plant refurbishment;
- To manage peak capacity requirements when our people are fully utilised – for example some civil and electrical construction work; and
- Where the work type is not core business to Counties Power – such as construction of substation buildings.

Using our forward work plans, we can forecast work volumes and balance work programmes to get the best utilisation of our people. Programmes such as preventative and corrective maintenance can be balanced with project work to manage peak capacity constraints and ensure high utilisation.

4.5 Risk Management framework

Risk management and asset management are intricately linked. We recognise that risk management is an integral part of good management practice, corporate governance, and it is central to effective asset stewardship. We are committed to maintaining an environment that effectively minimises risk exposure to acceptable levels and ensures compliance with legislation as well as industry and organisational standards and codes. Our Risk Management Framework is aligned to the *ISO 31000:2009 Risk management – Principles and guidelines* standard and it ensures that all our risks are identified, understood and managed consistently across all levels of our business. We assess our risks in accordance with our set consequence and likelihood ratings. We monitor, treat, control and manage all of our known risks. Responsibilities for managing risk are clearly allocated. Our Risk management framework strengthens our asset management decision making and practices. We apply risk management in all our business activities, including policy development, business planning and change management.

Our Risk management framework consists of the following components:

- Risk Management Policy;
- Risk management process;
- Risk management plans;
- Risk registers; and
- Risk reporting.

4.5.1 Risk Management Policy

We have a Risk Management Policy that establishes the context for our risk management activities and ensures that the risk management process is integrated with all organisational policies, processes, and practices to support efficiency and effective management. Our Risk Management Policy also outlines our risk management principles, and the roles and accountabilities for risk management.

Accountabilities and responsibilities

The following table presents the roles and responsibilities for risk management throughout the company:

Position	Roles and Responsibilities
Board of Directors	Corporate governance Independent review of risks and associated mitigations
Chief Executive	Risk management sponsor Representative to the Board of Directors Oversight of risk management process
Leadership Team (LT)	Ensure risk identified and managed to acceptable levels Risk management framework is in place and continuous Legislative and governance obligations are met Integration of risk management with policies, process and practices
Chief Financial Officer	Risk management administrator, in addition to LT responsibilities Schedule formal review sessions Ensure governance reporting obligations met
Managers and Team Leaders	Promote risk management culture Identify, manage and monitor risks in their groups Participate in risk planning, training and review sessions Assign and undertake responsibilities
Risk Owners	Support risk management within their area of responsibility On-going identification and assessment of risks, and responding appropriately relative to objectives Management of the relevant risk, within acceptable risk tolerance levels
Staff members	Awareness of risk management and process Everyday identification and management of risks and improvement actions to minimise risk events and impacts

Figure 4-4 Overview of Risk Management accountabilities and responsibilities

4.5.2 Risk Management process

Our risk management process is designed to ensure that risk management decisions are based on a robust approach, assessments are conducted in a consistent manner and a common language is used and understood across our business. Our risk management process comprises the following seven steps:

Establish the context

Many factors are considered including both internal and external parameters such as operating environment, stakeholders, internal structure and capabilities, and the risk appetite of the business.

Risk identification

Our risks are identified through operational processes including Hazard Identification by employees in the field, team and project meetings, our Health and Safety management process, and our Public Safety Management System. Risk identification is also undertaken by members of the Leadership Team and senior staff as part of the audit and review process.

For identification purposes, we have grouped our risks into five types. These are:

- **Financial**: Risks with consequential impact on cash flow, balance sheet and financial liability;
- **Safety:** A risk event that adversely impacts on the health and safety of the public, staff or contractors of the Company;
- **Operational:** Risks affecting the efficient operation of the company including service delivery, continuity and recovery of the company. This includes customer relations and reputation;
- **Regulatory:** Risk of the Company failing to meet current or foreseeable legal obligations; and
- **Environment:** Potential or actual negative environmental or ecological impacts, regardless of whether these are reversible or irreversible in nature.

Risk analysis

We use both qualitative and quantitative methods during the risk analysis stage. All identified risks are analysed in terms of probability, frequency, and consequence criteria in the context of our business objectives. A numeric rating is applied against the criteria of probability, frequency, and consequence. Risk ratings are based on the result of the scoring of these criteria. The probability, frequency and consequence ratings are provided in Figure 4-5 and Figure 4-6 below.

Level	Rating	Probability of the event occurring	Description
10	Almost Certain	1 event in 1 to 2 years, > 50%	The event is almost certain to occur
7	Likely	1 event in 2 to 5 years, 50%	The event is likely to occur within 5 years
1	Possible	1 event in 5 to 10 years, 20%	The event could possibly occur in the next 5 – 10 years
0.5	Unlikely	1 event in 10 to 20 years, 10%	The event is unlikely to occur possibly within 10 – 20 years
0.2	Rare	1 event in 100 years, < 1%	The event may occur only in exceptional circumstances

Figure 4-5 Probability Rating

Level	Rating	Frequency of exposure to the risk of the event	Description
10	Daily/Continuous	> 1 exposure in 24 hours	Exposure expected within a day
6	Weekly/Frequent	> 1 exposure in 7 days	Exposure expected within a week
2	Monthly/Occasional	> 1 exposure per month	Exposure expected within a calendar month
1	Yearly/Seldom	> 1 exposure per annum	Exposure expected within a year
0.2	Rare	< 1 exposure per annum	Exposure expected to be less than once a year

Figure 4-6 Frequency Rating

Level	Description	Examples of Consequence
100	Catastrophic	Major unplanned service outage for over seven days; Very serious irreversible environmental impairment of ecosystem functions; One or more fatalities and or severe injury to staff, customers or public.
40	Major	Major unplanned service outage for up to seven days only; Very serious, long-term environmental impairment to ecosystem functions; Serious injuries and or disability to one or more staff, customers or public.
15	Moderate	Unplanned service outage for up to five days; Serious medium-term environmental effects; Serious injuries to staff, customers or public, requiring hospitalisation and or lost work days.
5	Minor	Unplanned service outage for up to three days unless it affects a key customer or occurs at a significant time (e.g. major sporting event or public holiday; Moderate short-term environmental effects, but not affecting ecosystem functions; Injury to a staff member, customer, or public requiring medical treatment.
1	Insignificant	Unplanned service outage for less than 24 hours unless it occurs at a significant time (e.g. major sporting event or public holiday; No measurable impact on biological or physical environment.

Figure 4-7 Consequence Rating

Risk evaluation

All of our identified risks are evaluated against our probability, frequency, and consequence numeric ratings listed above, to ascertain the residual risk score. This assists us in our decision making to ascertain which risks need treatment and the priority for treatment implementation.

Risk treatment

We treat a risk, depending on the numeric score it has been allocated in the analysis and evaluation stage. Risk treatment involves selecting one or more options for modifying risks, and these can include the following:

- Avoiding the risk by not commencing or continuing the activity;
- Accepting or increasing risk in order to pursue an opportunity;
- Removing the risk source;
- Changing the frequency or probability;
- Changing the consequences;
- Sharing the risk with another party or parties (e.g. contracts and insurance); and
- Retaining the risk by informed decision.

4.5.3 Risk register

Information from the risk management process is recorded, reported and monitored using our risk register. The Risk Register assists us to monitor and review risks in alignment with our business objectives.

4.5.4 Risk reporting and monitoring

All of our risks are periodically reviewed by our Leadership Team and are reported according to the residual risk score in Figure 4-8 below:

Residual Risk Score		Report to
> 400	Extreme	Board of Directors and Leadership Team
200 - 399	*High*	
70 - 199	Medium	Leadership Team and Operational Managers
20 - 69	Low	Operational Managers and Staff
< 20	Insignificant	

Figure 4-8 Risk reporting criteria

The Board of Directors receive detailed reviews of specific risks in monthly reports. They also receive a periodic report summarising the top risks that we face, and the treatment applied to those risks. The Leadership Team and other senior managers meet periodically to review our risk management position.

4.5.5 Project Risk Management planning

In addition to corporate level risk management activities, a risk management plan is produced for each activity or project the business undertakes. Each project risk management plan specifies the risks relating to that project and the approach to risk management includes the risk treatments, and any relevant task Job Safety Analysis (JSAs) and work standards that apply to the project.

The design and implementation of each project risk management plan is to consider our overall business objectives.

4.6 Public Safety Management System (PSMS)

Public safety is a critical component of our risk management framework. We adopt the requirements set out in NZS 7901:2008 *Electricity and gas industries – Safety management systems for public safety* to safeguard the public or their property from safety-related risks arising from the presence or operation of our network distribution assets.

In 2018, our certification continued after a review audit was conducted by Telarc against NZS 7901:2008. This follows recertification in 2015 and initial certification in 2012.

4.7 High Impact, Low Probability Events (HILP)

We are exposed to a number of potential HILP events, which could give rise to a major unplanned service outage for an extended period of time. HILP events are defined as having a widespread impact, but occurring rarely, and they are not always economically justifiable to avoid if this can be achieved at all. Accordingly, we have a responsibility to plan and manage for HILP events as best we economically and practically are able to. Within this context, our policy is to ensure the timely restoration of power supply, effective communication, a safe environment for staff, contractors and the wider community, and efficient provision of information tools for critical business activities should we be subject to a HILP event.

Our critical business activities relate primarily to safety and customer service, as well as security, reliability, and quality of supply. Events that could interrupt our critical business functions include natural disasters such as flood, tropical cyclones and windstorms, electrical storms, volcanic eruption, or earthquake, airspace incident, asset failure, communications failure, Information System security breach or loss, and unplanned loss of supply from Transpower or generators.

Note: Lack of generation capacity (e.g. due to a “dry year”) leading to supply restrictions are not included in the definition of HILP events as they are able to be managed in advance of any impacts.

4.8 Emergency response and contingency plans

We place an emphasis on pre-event planning for HILP events. Our assets are designed to provide a certain level of resilience under a normal operating environment as defined in our security of supply and planning guidelines. Natural disasters and emergency situations subject our assets and operations to conditions other than that for which they are designed to withstand, which may result in outages or other supply issues. While our network is not primarily designed to withstand significant HILP events, as costs are prohibitive, we have response policies, procedures and contingency plans in place and critical emergency spares are held in stock to ensure that our power supply is restored in as minimum time as possible. Our contingency plans provide details concerning expected events and the necessary response. These include, for example, contingency operational plans for loss of SCADA and communications networks, and switching schedules associated with the loss of transformer banks and subtransmission lines.

When reviewing network development projects, the issue of resilience under abnormal conditions is considered as part of the selection process from the available options.

Lifeline Utility and Engineering Lifeline Groups

To help make New Zealand resilient to disasters, the Civil Defence and Emergency Management (CDEM) Act 2002 stipulates the responsibilities and roles of key organisations that provide an essential service within New Zealand. Our core business of electricity distribution is an essential service and under the CDEM Act we have been classified as a "Lifeline Utility." As such, we must:

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

We are members of the Auckland Engineering Life Lines Group and the Waikato Engineering Lifelines Group. Lifeline groups are a voluntary group of organisations with representatives from territorial authorities, major utilities and the transportation sector. The emphasis of these groups is on pre-event planning rather than taking a post-event operational role. Collaborating with other Life Line members provide a much greater understanding of the general vulnerabilities and interdependencies that individual utility response plans need to consider. As well as further developing the preparedness of lifelines operators for major hazard events, one of the key areas of emphasis is to create and maintain awareness of the importance of lifelines to the community at large.

Civil Defence Plan

We have a Civil Defence Plan in place which details how we respond to a Civil Defence Emergency.

Information system security breaches or losses

We place an emphasis on the security of information within all business systems. We have in place comprehensive data backup and recovery policies. Our operating systems and SCADA systems are particularly critical, therefore they require effective protection from external and malicious access. We participate in the New Zealand Control Systems Security Information Exchange. This organisation is designed to facilitate the exchange of information between its members, in a confidential and trusted environment, concerning threats, vulnerabilities and incidents of electronic attack on control system networks and environments.

4.9 Asset Management maturity

4.9.1 AMMAT

The Asset Management Maturity Assessment Tool (AMMAT) is a self-assessment required by the Commerce Commission as part of the information Disclosure Schedules, included in Appendix C. It is a set of questions derived from the UK Standard PAS 55 (now superseded by ISO 55000) which requires Distributors to rate their asset management capability through 31 questions.

The purpose of the AMMAT is for Distributors to identify the level of maturity they have in asset management activities and opportunities for improvement and provide a structured method of benchmarking.

4.9.2 AMMAT assessment

The completed Asset Management Maturity Assessment Tool is included Schedule 13 of this AMP.

The results from this are shown in the figure below and are consistent with previous years, with scores generally of 2, with some achieving a score of 3, and an average of 2.3.

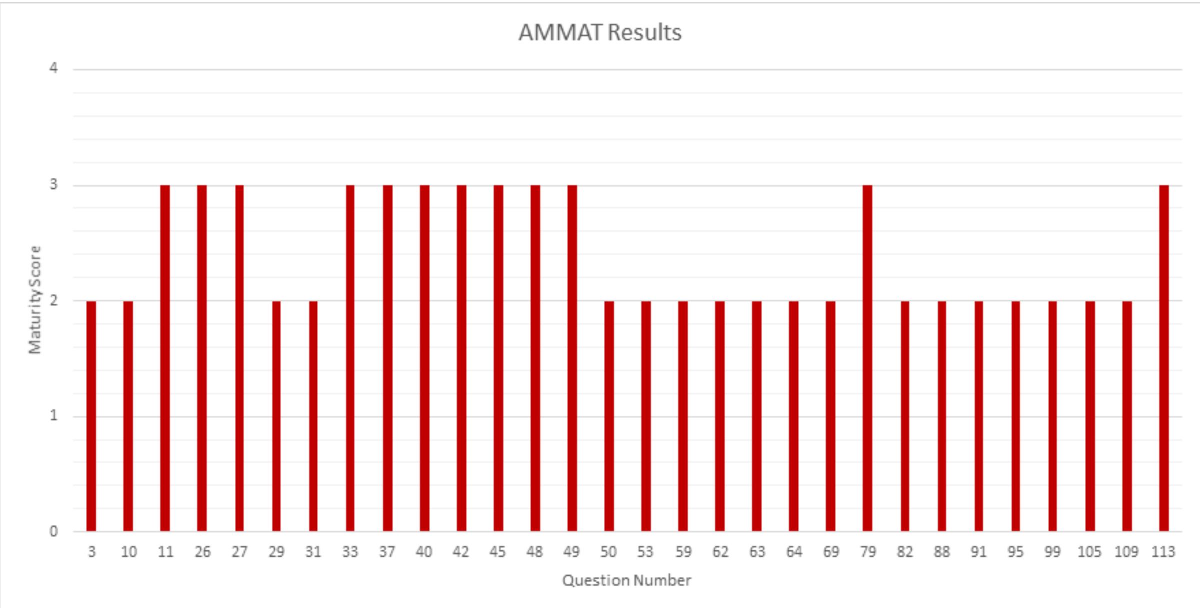


Figure 4-9 AMMAT Results

4.10 Improvement Initiatives / Continuous Improvement

A review of the AMMAT results, along with the wider review of asset management practices in the business currently underway shows there are a number of areas of improvement required, with focus in the following areas. Updates will be provided in future year plans.

Asset management policy and strategy – further development of these documents, including socialising and sharing these within the business and relevant information being provided to stakeholders, including:

- Alignment of asset management strategy to lifecycle plans across all asset groups; and

- Communication of relevant business information through dashboards and live reporting which are being developed.
- Asset management plans – aside from this AMP which is produced to meet regulatory compliance requirements, more detailed asset management plans for specific asset categories are required to be developed and maintained, including the role different parts of the business play in those plans. Asset lifecycle management plans for specific asset groups continue to be developed and will determine appropriate requirements including asset performance requirements and asset criticality assessments.

- **Training, awareness and competence** – improved structure and documentation relating to how resources are planned, and for the organisation to have sufficient trained and competent resources to deliver on the requirements for asset management activities. We are continuing to develop our competency framework, with a focus on asset management activities;

- **Information systems and management** – improvements in how the organisation determines the requirements for and manages the systems for asset management activities. This plan has already identified the need for a major systems review and renewal, and these will be addressed as part of this work including:

    - Scoping and delivery of a relevant Asset Management system with consideration to the integration of existing QMS, CRM, Works Management and HSE/Quality systems; and
    - Defining data requirements within the Asset Management system for our asset management activities.

- **Risk management** – improving how we manage asset specific risk, including further development of asset management strategies focussed on that risk. Additionally, how we manage corrective actions arising from risk assessments of incident reviews;
    - Asset risks and defect management through dashboards and the introduction of a relevant Asset Management system;
    - Improvements to risk assessment methods used for asset specific risks and defects to ensure continuity and consistency; and
    - Process and procedural improvements to manage asset risk through the lifecycle of an asset group.

- **Asset lifecycle activities** – improvements in the development and documentation relating to design, construction and maintenance activities. These are being addressed through standards review and development which started in 2017, focussing on high risk activities first, including:
    - Asset group performance requirements being defined;
    - Maintenance and Inspection Standards defined and updated; and
    - Lifecycle Costing and Plans further developed for all major asset groups.

- **Investigation, audit and corrective actions** – improvement in the documentation and processes around asset management related audit, outcomes and corrective actions. Linking those processes back into business as usual activities.

5 Renewal and Maintenance

This chapter outlines the population profiles, the inspection and maintenance requirements, and the replacement expenditure for each of our asset categories. Our asset categories covered in this chapter are:

- Subtransmission;
- Zone substations;
- Distribution and LV lines;
- Distribution and LV cables;
- Distribution substations and transformers;
- Distribution switchgear;
- Grid scale battery storage system;
- Other network assets;
- Other operational assets; and
- Assets owned by Counties Power at GXPs.

The refinement of our fleet management practices is an ongoing activity within Counties Power. Accordingly, the practices recorded in here are under review and with the further development of comprehensive asset fleet strategies to continue over the next 12 months. We also expect our management planning to continue to evolve over this time.

5.1 Asset quantity summary

A summary of our asset quantities is provided in section 2.7. The following sections provide details by category of assets.

5.2 Subtransmission

The subtransmission network transports electricity from Transpower's Grid Exit Points to our zone substations. It consists of:

- Overhead lines, which in turn are made up from poles, cross arms and conductors;
- Underground cables;
- Substation buses and support structures; and
- Circuit Breakers.

We have six 110kV subtransmission circuits with a total length of 65.8 km, all of which is overhead line. The total length of 33kV subtransmission circuits on our network is 72.3 km of overhead lines and 1.1 km of underground cables. Portions of our subtransmission network have reached the end of their life expectancy or have capacity constraints and are scheduled to be rebuilt during this AMP planning period. This is discussed further in Section 6 – Network Development.

5.2.1 Quantity and life expectancy of subtransmission assets

Table 5-1 below summarises the construction material, quantity and life expectancy of our subtransmission network by asset type.

Asset	Construction Type	Quantity	Life Expectancy
Subtransmission Poles	Concrete Pole	1,345	80 years
	Wooden/other Pole	11	45 years
	Steel Pole	147	55 years
	Steel Tower	10	55 years
Subtransmission Lines	110kV	65.8 km	80 years
	33kV	72.3 km	80 years
Subtransmission Cables	33kV	1.1 km	55 years

Table 5-1 Subtransmission asset summary (asset quantity as at Sep-18)

The age profile, condition, inspection and maintenance requirements and the 10-year forecast expenditure for each asset class are described below.

5.2.2 Management approach

Our subtransmission assets are critical to provision of services to our stakeholders and are the backbone of our network. The impact of a failure on a subtransmission circuit has the potential to affect a large number of customers for a long duration.

Our approach is to ensure that these assets are subject to robust inspection and corrective maintenance programmes, as well as appropriate asset renewal programmes, to ensure their reliability and availability. Defects are to be addressed with high priority, and investigations into failures undertaken to identify underlying issues so as to avoid recurrence of issues given the importance of these circuits.

5.2.3 Subtransmission lines and poles

Our subtransmission network is predominantly overhead line circuits, supported by wood, concrete and steel poles, as well as a section of line supported by steel lattice towers. Older parts of our subtransmission network have copper and ACSR conductors and since the mid-1990s, we have used AAC as the standard conductor for our subtransmission network. We select the most appropriate type and size of conductor on a project specific basis.

Age profile

Figure 5-1 shows the age profile of our subtransmission network.

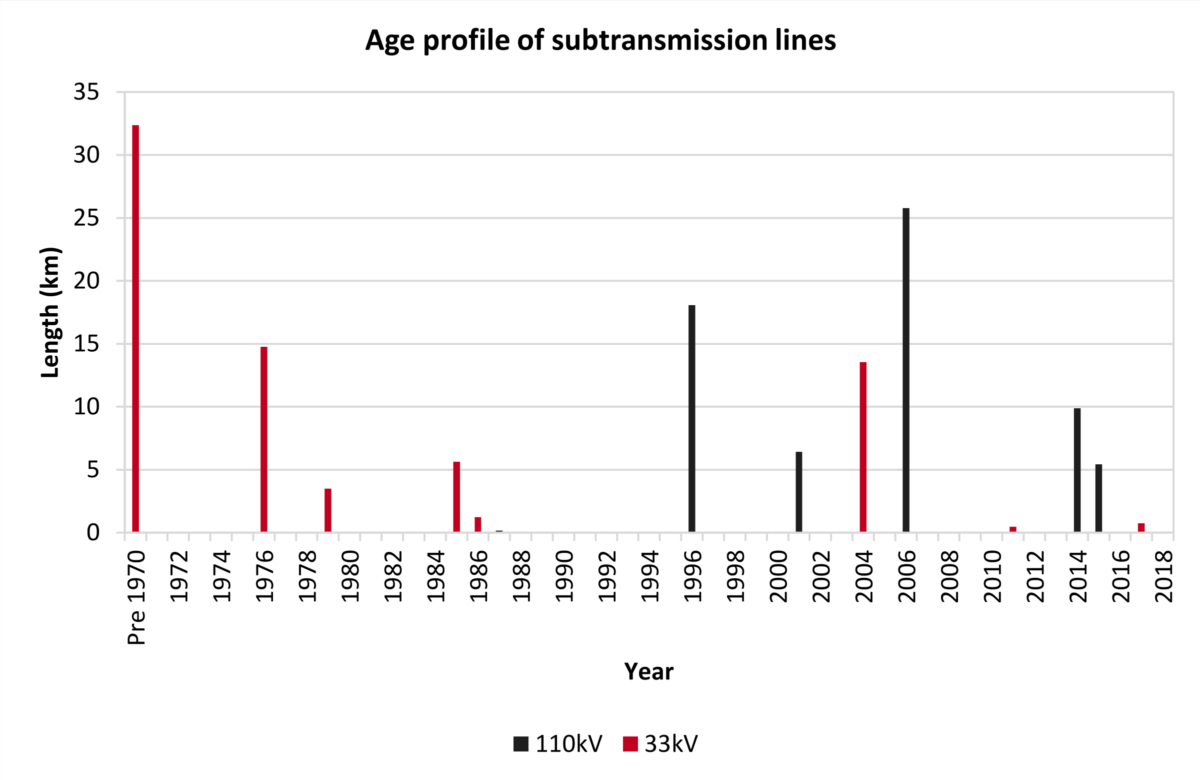


Figure 5-1 Age profile of Subtransmission Lines

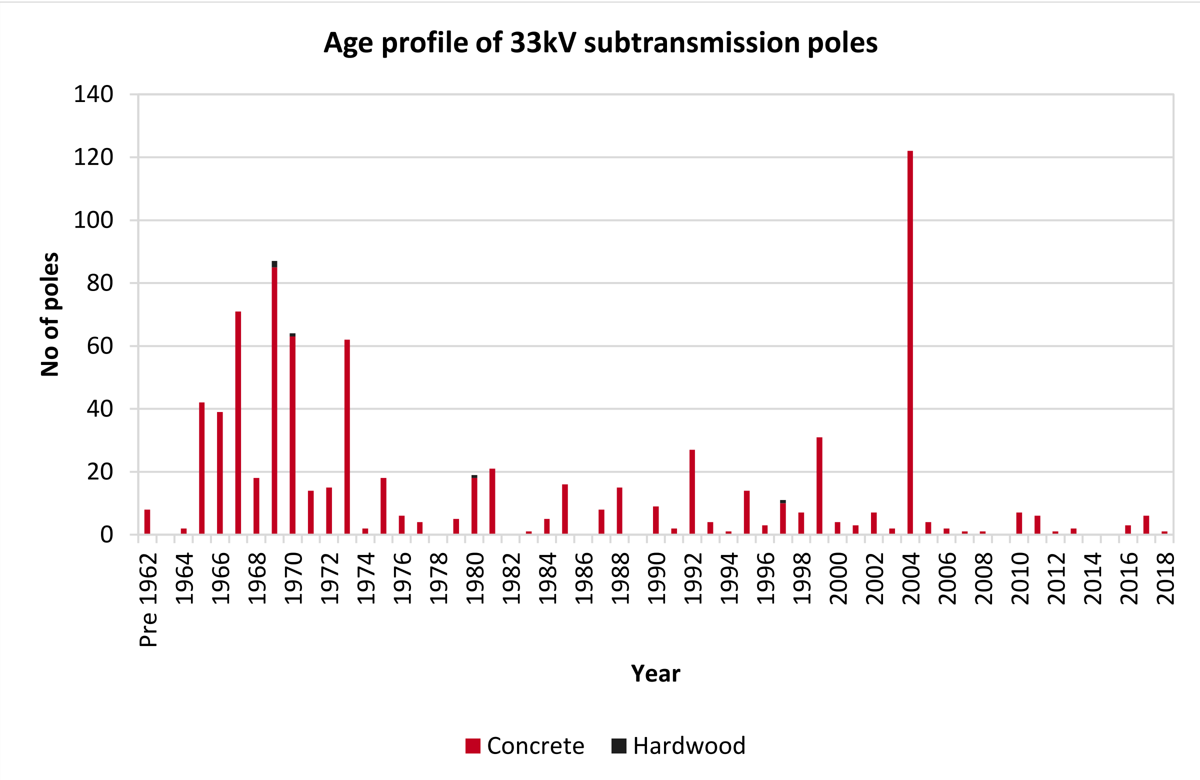


Figure 5-2 Age profile of 33kV subtransmission poles

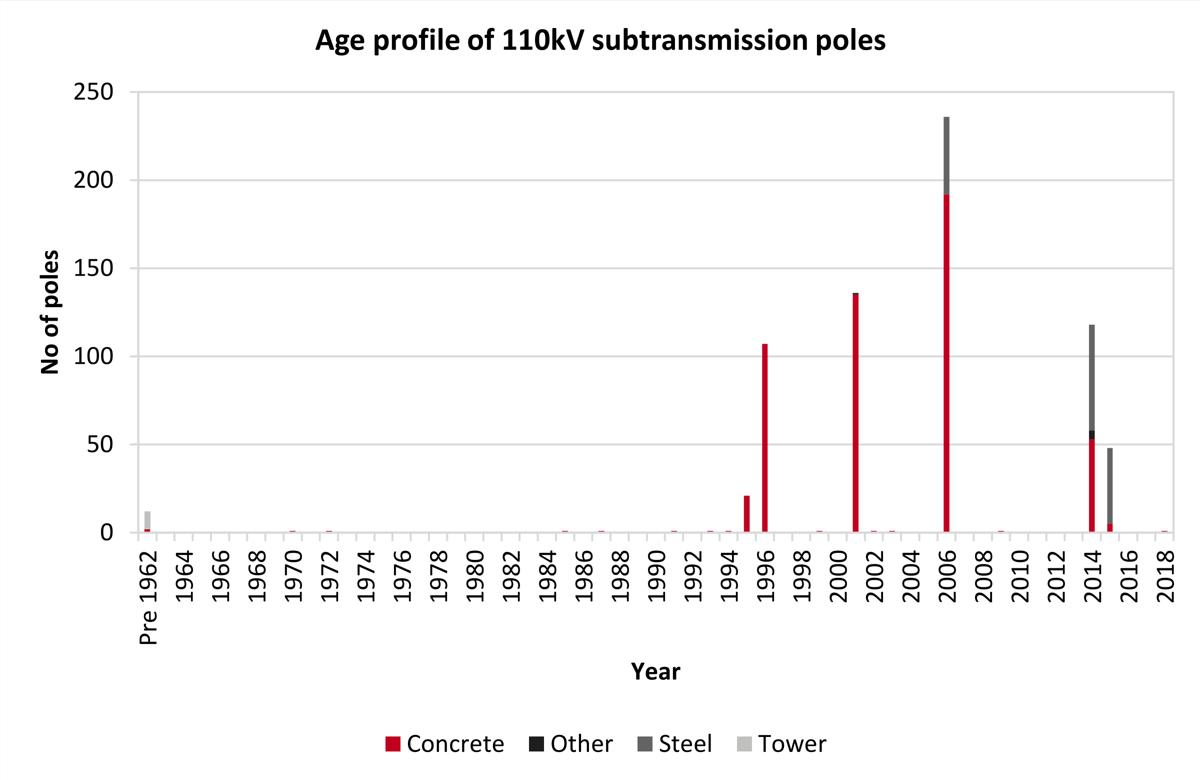


Figure 5-3 Age profile of 110kV subtransmission poles

Inspection and maintenance practices

Our inspection cycles for subtransmission lines and poles are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly
Insulator Washing – Glenbrook area	Routine Servicing	Annual
Vegetation Survey	Inspection	Area Specific

Table 5-2 Inspection cycles for subtransmission lines and poles

Corrective maintenance is undertaken on overhead subtransmission lines when defects are identified as part of routine asset condition surveys. Examples include insulator and cross arm replacement, replacement of possum guards, stay wires, and other minor components.

In areas subject to heavy pollution, particularly around the Glenbrook steel mill, insulator washing is undertaken periodically to reduce contaminant build up and reduce the likelihood of tracking and flashover.

Renewal programme

Eastern area

The 110kV lines in the Eastern Area supplying Opaheke, Pukekohe and Tuakau are generally in good condition as they have been constructed in the past 20 years, and only require minor maintenance.

One section of line supplying Opaheke and Ramarama is constructed on steel towers which are part of a former transmission line originally constructed by Transpower's predecessors but now owned by Counties Power. These towers are over 85 years old and are at a stage of life where major component replacement will be required in this planning period, as the last major remedial works programme was undertaken in the early 2000s. A detailed condition assessment was undertaken in 2017 and identified 30 insulators with deteriorated condition, and damage to tower leg members at one site. Replacement work was completed in early 2018 to address the identified issues ahead of the forecasted need for a line rebuild in 2024/25 which has an estimated cost of $3.0M. The proposed establishment of a Drury GXP removes the need for this line from a security perspective, however there are strategic benefits to having subtransmission links between GXPs to mitigate HILP risks and these will be assessed further as part of the area redevelopment.

The overhead line to Mangatawhiri is in below average condition, with some components at end of life requiring replacement within this planning period. These issues will be addressed as part of a wider development plan for this area and as such no specific replacement project is included in this section of the plan.

Western area

The 33kV subtransmission line from Waiuku to Maioro is at end of life, with significant maintenance required during the planning period. Given the previous uncertainty around the future of the mine site operated by NZ Steel, the major consumer on this line, the rebuild of the line will only be undertaken once agreed with NZ Steel through appropriate commercial arrangements. A condition based refurbishment will be required if the line remains in service through the planning period. A budget provision of $900,000 has been allowed for in the later part of the planning period subject to the future of the substation, and customer requirements.

The 33kV East line from Glenbrook to Waiuku has identified capacity constraint within the planning period, and any condition based renewal will be undertaken as part of a larger capacity augmentation project detailed in section 6 Network Development.

Out of service lines

As well as in-service subtransmission lines, we also own lines which are not currently in use - however we may use these again in future. After a review of future needs, two unused lines have been removed in the past year leaving one route only which we have to inspect and maintain to ensure it does not present any public safety risks.

- The remaining out of service line is the Bremner Road to Karaka 33kV line, this will remain in place and it will be inspected with a detailed condition assessment in 2019/20. This has been allowed for in our corrective works programme.
- Bombay to Tuakau 33kV line sections along Pokeno Road to Potter Road, and Huia Road to Pokeno Road has been removed in 2018/19 under our corrective works programme. The remaining section from Bombay GXP to Huia Road will remain in service as it has strategic value for supply to new developments in the area. This section will be inspected and maintained as part of our preventative maintenance programme.

5.2.4 Subtransmission cables

We have 1.1 km of 33kV Cross-linked polyethylene (XLPE) cables[14] installed in our subtransmission network at various locations. The life expectancy of our 33kV XLPE cables is 55 years, with the first replacement expected well beyond this planning period.

Age profile

Figure 5-4 shows the age profile of our subtransmission cables. The age of XLPE cables ranges from 7 to 38 years old. The weighted average age of the 33kV subtransmission cables is 18 years.

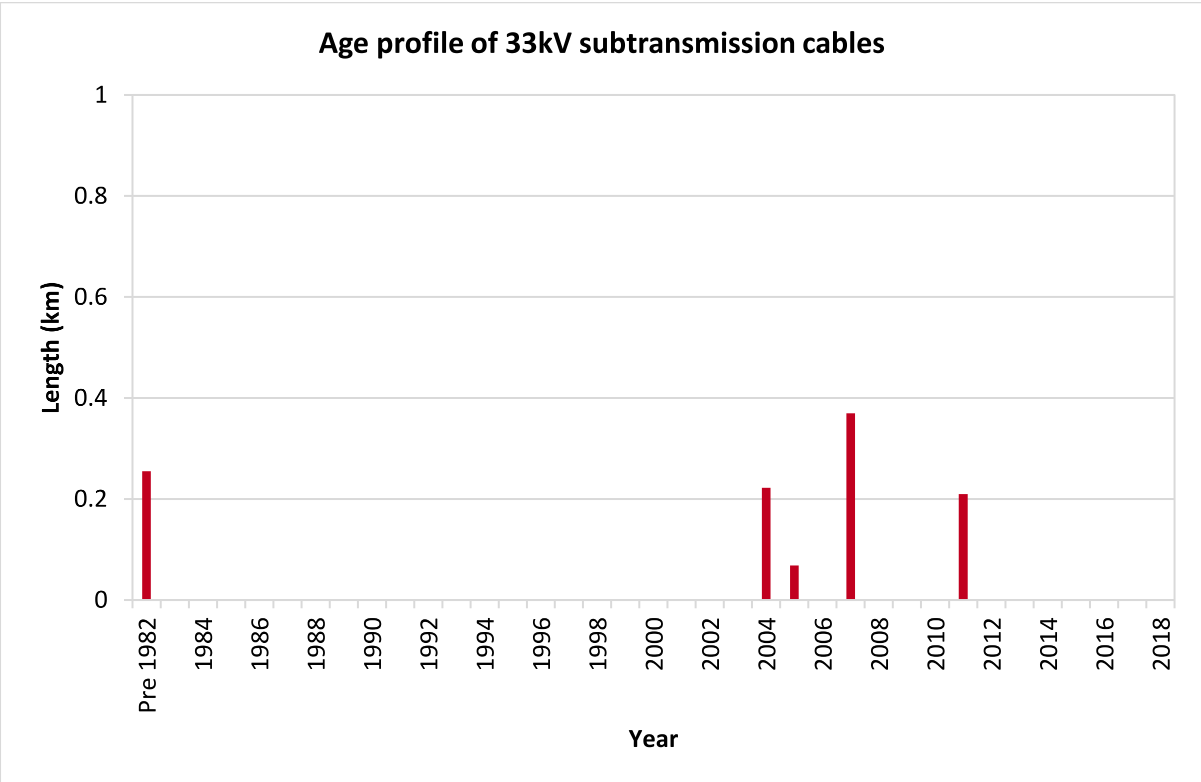


Figure 5-4 Age profile of 33kV Subtransmission Cables

[14] Based on operating voltage.

Inspection and maintenance practices

There are no specific planned maintenance activities on subtransmission cables on our network as we have a small quantity and their construction type is generally very reliable. Cable terminations are inspected as part of the overhead line asset condition survey, and defects remediated as required.

Diagnostic tests can be undertaken on an 'as-required' basis where performance indicates an issue exists or following a fault. These tests include insulation resistance testing, serving tests and cable partial discharge tests.

Renewal programme

Our management strategy for 33kV cables is to reactively replace them when required. Given the age of the cables we do not expect any renewals will be required within the planning period.

5.2.5 Summary of Subtransmission Expenditure Forecast

Expenditure Forecast ($000)	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Capital Expenditure										
Maioro Line Refurbishment						450	450			
Bombay - Ramarama Tower Line Renewal						3,000				
Other Subtransmission Renewal	50	50	50	50	50	50	50	50	50	50
Capital Expenditure Total	50	50	50	50	50	3,500	500	50	50	50
Operational Expenditure										
Subtransmission lines	140	110	110	110	110	110	110	110	110	110
Operational Expenditure Total	140	110	110	110	110	110	110	110	110	110

Table 5-3 Subtransmission expenditure forecast summary

5.3 Zone Substations

Zone substations consist of power transformers, switchboards and substation buildings. Power transformers convert subtransmission voltage (110kV and 33kV) to distribution voltage (22kV and 11kV). Switchboards control and protect the network.

We own eight zone substations of which five operate at 33/11kV and three operate at 110/22kV. The construction dates of our zone substations range from 1956 to 2014. Six of our zone substations have N-1 security and two have N security. Our security standard is discussed in further detail in Section 6 - Network Development. In addition to the eight zone substations, we have one major switching station at Pukekawa and is covered in this section.

5.3.1 Quantity and life expectancy of zone substation assets

Table 5-4 below summarises the construction material, quantity and life expectancy of our Zone Substation assets.

Asset	Construction Type	Quantity	Life Expectancy
Substation Buildings		9	50 years
Power Transformers	110/22kV	6	60 years
	33/11kV	9	60 years
Circuit Breakers	110kV CBs	14	45 years
	33kV CBs	12	45 years
	22kV CBs	44	45 years
	11kV CBs	36	45 years
Station Disconnectors	110kV Disconnectors	2	45 years
	33kV Disconnectors	29	45 years

Table 5-4 Zone substation asset summary (asset quantity as at Sep-18)

The age profile, condition, inspection and maintenance requirements and the 10-year forecast expenditure for each asset class are described below.

5.3.2 Management approach

Zone Substations, like subtransmission assets, are a critical part of our network, and have high impact when they don't perform as expected. They are also prominent parts of the communities in which they are located, and therefore need to be 'good neighbours' – clean, tidy, secure and not causing harm to public.

Key maintenance outcomes for our zone substations are to ensure they are safe and secure, that they meet network and environment performance standards (including seismic compliance, oil containment, discharge controls, noise levels, etc.), that they are free of vermin and nesting animals and are not vandalised. Routine inspections also inform us of when major plant is deteriorating or needs corrective maintenance.

5.3.3 Power transformers

Power transformers at our Zone Substations step down the subtransmission voltage (110kV or 33kV) to distribution voltage (22kV or 11kV).

We have 15 power transformers at our Zone Substations with installation dates ranging from 1956 to 2014. Power transformers installed prior to 1990 were 33/11kV. Since 2000, six 110/22kV transformers have been installed in line with our plans to develop higher subtransmission and distribution voltages within the eastern region of our network.

Age profile

Figure 5-5 shows the age profile of our power transformers. The weighted average age of the transformers is 33 years.

Based on a life expectancy of 60 years, we expect to be replacing the oldest Zone Substation power transformer in our system (the 33/11kV, 5MVA transformer at Ramarama) within the next 3 to 5 years. Network Development Plans outlined in Section 6 address these issues.

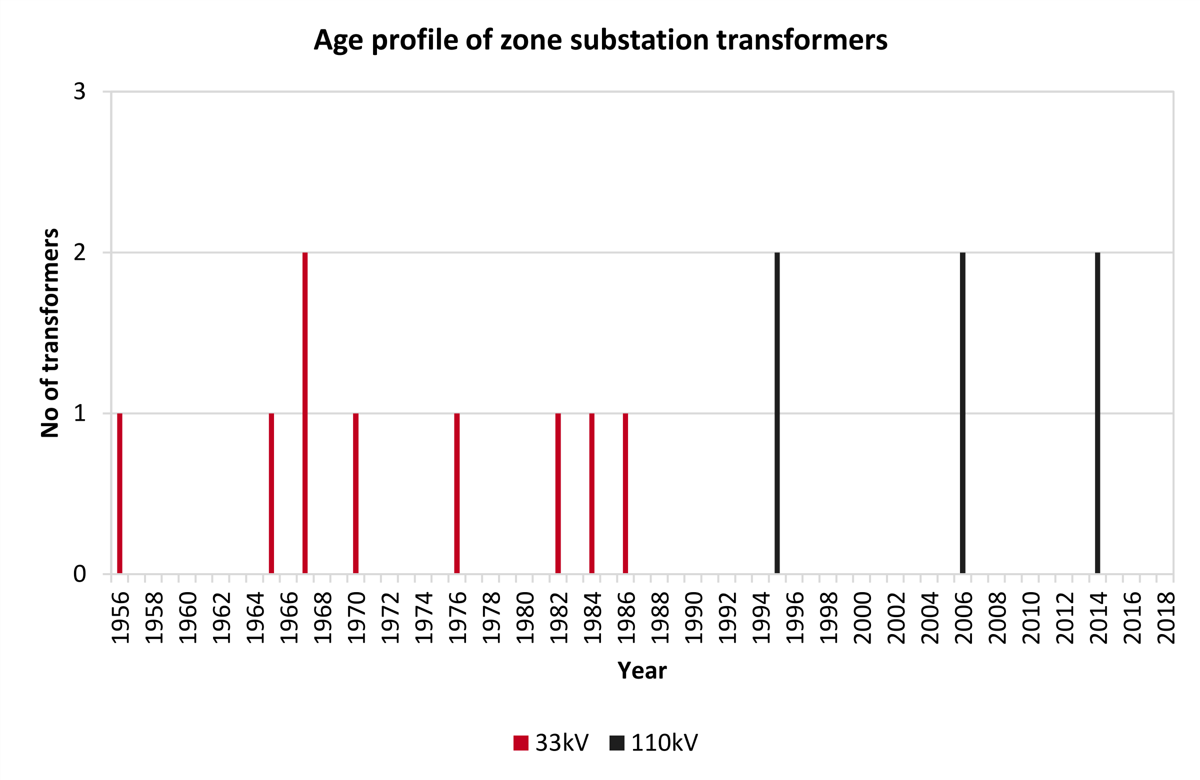


Figure 5-5 Age profile of Zone Substation Transformers

Inspection and maintenance practices

Our inspection cycles for Zone Substation power transformers are:

Activity	Type	Frequency
Routine Visual Inspection	Inspection	Monthly with Sub Visit
Detailed Inspection and Condition Assessment	Inspection	Annual
Transformer oil DGA analysis	Routine Test	Annual
Transformer and Bushing Maintenance	Routine Servicing	3 yearly
Tap changer Maintenance	Routine Servicing	3 yearly / or 10,000 operations

Table 5-5 Inspection cycle for Zone Substation Power Transformers

Renewal/Refurbishment programme

Our current practice is to carry out mid-life refurbishment on zone substation power transformers based on condition and age. Carrying out mid-life refurbishment ensures the maximum transformer life is obtained with minimum lifetime costs. This work is often carried out in conjunction with substation upgrades and involves the transformers from one location being refurbished before reinstallation at a new location. Being able to exchange transformers minimises the time the substation operates at a reduced security level, i.e. only one transformer available in service.

Prior to this AMP period the two (10/20MVA) ex-Tuakau transformers have been refurbished and one relocated to Waiuku. The Waiuku (10/20MVA) transformer has been refurbished and relocated to Karaka, the Karaka transformer was at end of life and has been scrapped.

In this AMP period the plan is as follows:

- The second of the two ex-Tuakau transformers, (10/20MVA) will be moved into Waiuku in conjunction with the rebuilding of the substation, the capacity is unchanged, and the substation will then have two refurbished transformers;
- The Waiuku transformer (10/20MVA) will be refurbished ready for installation at Karaka, the capacity is unchanged, and the substation will then have two refurbished transformers;
- The Karaka transformer (10/20MVA) will be refurbished for re-use at Maioro, to replace one of the two existing 7.5MVA units, thus increasing the substation capacity;
- The condition of the Maioro transformers will be assessed at that time and a decision made on their future.

Each of these sites has a development path outlined in Section 6 Network Development.

5.3.4 Zone substation switchgear

Age profile

We own 106 circuit breakers and 31 disconnectors at our Zone Substations. Figure 5-6 shows the age profile of our Zone Substation circuit breakers. The weighted average age of the circuit breakers is 26 years.

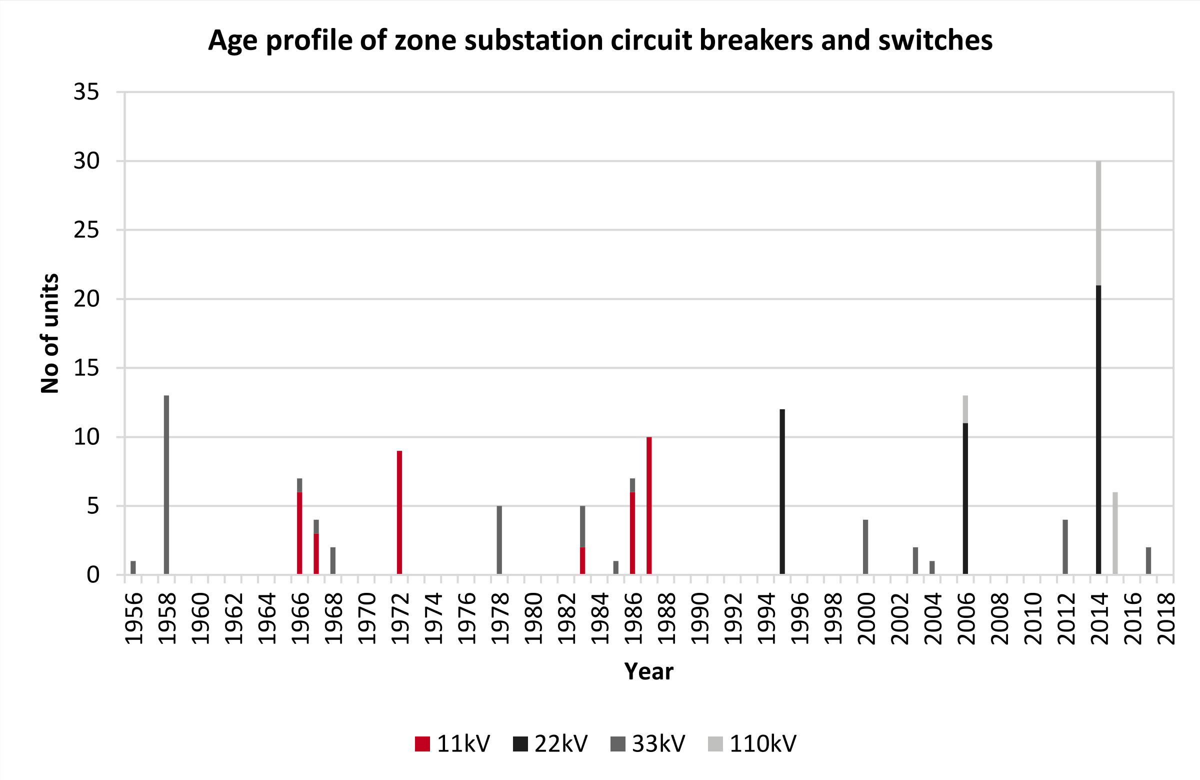


Figure 5-6 Age profile of Zone Substation Circuit Breakers and Switches

Inspection and maintenance practices

Our inspection and maintenance cycles for Zone Substation switchboards and switchgear are:

Activity	Type	Frequency
110kV or 33kV Circuit Breaker Inspection (incl. partial discharge and thermal imaging)	Inspection	Annual
110kV or 33kV Gas Insulated CB Maintenance	Routine Maintenance	5 yearly
33kV Oil Insulated CB Maintenance	Routine Maintenance	3 yearly / or 3 fault operations
22kV or 11kV Switchboard Inspection (incl. partial discharge scan and thermal imaging)	Inspection	Annual
22kV or 11kV Circuit Breaker Maintenance (Gas/Vacuum)	Routine Maintenance	5 yearly
11kV Circuit Breaker Maintenance (Oil)	Routine Maintenance	3 yearly / or 3 fault operations

Table 5-6 Inspection and Maintenance cycles for Zone Substation Switchboards and switchgear

Renewal programme

During the planning period, we will need to replace 11kV switchboards at Waiuku, Maioro, and Mangatawhiri due to age and condition. These switchboards are air insulated with oil filled circuit breakers. This expenditure is included in the forecasts, however as the network development plan further progresses, these replacements may be addressed through alternative projects such as area development plans leading to new substation builds.

The last older style 33kV bulk oil circuit breaker on the network at Waiuku will be replaced as part of a substation redevelopment project for Waiuku in 2019/20 (see section 6.5.5).

There will be a need to replace the 11kV switchboard at Maioro, due to age and condition, around 2024/25. Annual switchboard partial discharge testing and inspection will continue to be part of the ongoing condition monitoring of the switchboard. An option exists to utilise the switchboard from the existing Ramarama substation if and when it is decommissioned, and the timing is right (see Section 6), or to purchase a new switchboard for the site. The expected cost of this project ranges from $100,000 to $350,000 depending on the final solution selected. This investment is dependent upon the future of the Maioro site and major customer requirements, however an allowance of $350,000 has been made in 2024/25.

The 22kV bus section circuit and feeder breakers at Opaheke had additional maintenance carried out in 2018 to address a condition issue associated with partial discharge. Whilst the work carried out appears to have resolved the issue at this stage we will continue to monitor the switchboard and have allowed for additional maintenance to be carried out on an annual basis with an allowance of $10,000 until switchboard replacement in 2022/23 for capacity reasons (see section 6.4.4).

5.3.5 Other primary equipment

This category includes primary equipment at our Zone Substations not covered by other categories such as outdoor bus structures, instrument transformers and earth grids.

Inspection and maintenance practices

Our inspection and maintenance cycles for Zone Substation other primary equipment are:

Activity	Type	Frequency
Outdoor Bus Structures	Inspection	Annual
Instrument Transformer Inspection	Inspection	Annual
Substation Earth Grid Inspection	Inspection	Annual
Substation Earth Grid Test	Routine Test	3 yearly

Table 5-7 Inspection and maintenance cycles for Zone Substation other primary equipment

Renewal programme

There are no identified renewals required for other substation primary plant included in this plan and expenditure forecasts. Any replacement or renewal activity will arise from routine inspection and condition assessment, or as a result of other primary plant upgrade (e.g. new instrument transformers required with a new circuit breaker).

5.3.6 Substation buildings and grounds

Substation buildings provide physical protection for indoor switchgear, metering, control, protection and communications equipment against the environment.

Age profile

Figure 5-7 shows the age profile for our substation buildings. We have 9 buildings at our Zone Substations with installation dates ranging from 1954 to 2014. One substation building at the old Tuakau 33kV substation is no longer used as part of the distribution network and will be converted into a disaster recovery control room during 2019. The weighted average age of our buildings is 39 years.

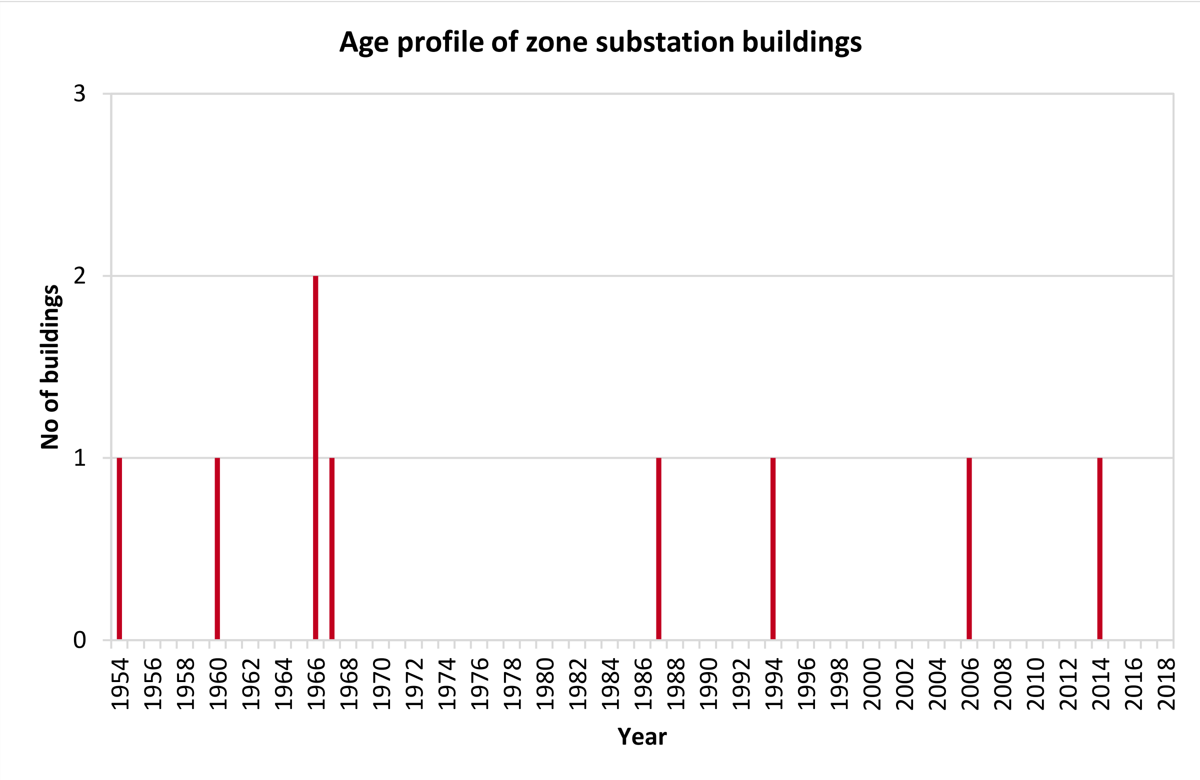


Figure 5-7 Age profile of Zone Substation Buildings

Inspection and maintenance practices

Our inspection and maintenance cycles for Zone Substation buildings and grounds are:

Activity	Type	Frequency
Routine Substation Inspection	Inspection	Monthly
Building and Grounds Maintenance	Routine Maintenance	Monthly

Table 5-8 Inspection and maintenance cycles for Zone Substation buildings and grounds

Substation oil compliance programme

As part of our commitment to the environment, and to manage compliance requirements, it is necessary for us to manage the issue of potential leaks or spills of transformer oil at substation sites. The majority of our substation sites have bunded areas around power transformers and more recently constructed substations have been built with oil separators. Oil separators are to be retrofitted to older sites at Karaka and Maioro substations as standalone projects in 2019/20 at an estimated cost of $600,000 and a system will be installed at Waiuku as part of its re-development.

Renewal programme

The substation buildings are generally in good condition, with minor repair and renewal work undertaken as required.

An Initial Evaluation Procedure (IEP) has been undertaken to determine the buildings seismic strength for seismic risk according to building importance level of 4 (IL4) for all substation buildings and, with the exception of Waiuku, they have been found to have greater than 33% NBS which means that they are not earthquake prone and no further structural engineering investigations are required for those sites. Pukekohe, Tuakau and Opaheke have all been constructed within the past 20 years to modern building standards.

The Waiuku zone substation building has been assessed as having less than 33% of the new building seismic standard (NBS) and requires strengthening, however it is being redeveloped as part of the substation development plan for Waiuku (refer to Section 6 - Network Development).

Older industrial buildings often included materials containing asbestos which it is now recognised must be handled carefully to avoid human exposure to free asbestos particles. An inspection and testing program has been carried out in late 2018 across all of our substation buildings to assess if any further action is needed and the next AMP will include any projects required to manage asbestos compliance.

5.3.7 Summary of zone substation expenditure

Expenditure Forecast ($000)	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Capital Expenditure										
Replace Maioro 11kV Switchboard						350				
Oil Separator Plant	600									
Power Transformer Refurbishment			300	300	300					
Other Zone Substation Renewal	50	50	50	50	50	50	50	50	50	50
Capital Expenditure Total	650	50	350	350	350	400	50	50	50	50
Operational Expenditure										
Zone Substation transformers	150	160	120	120	120	120	120	120	120	120
Zone Substation switchgear	120	120	120	110	110	110	110	110	110	110
Zone Substation other equipment	90	90	110	110	110	110	110	110	110	110
Zone Substation buildings and grounds	90	90	90	90	90	90	90	90	90	90
Operational Expenditure Total	450	460	440	430	430	430	430	430	430	430

Table 5-9 Zone Substation expenditure forecast summary

5.4 Distribution and LV lines

We transfer electricity from our zone substations to our consumers through our 22kV or 11kV distribution network and our 400V Low Voltage (LV) network which consists of both overhead lines and underground cables. Lines and Cables have quite different maintenance and renewal requirements and are treated separately in asset management planning.

We have 570.6 km of 22kV lines, 894.6 km of 11kV lines and 732.1 km of 400V LV lines. Our conductors consist of a mix of copper and aluminium (ACSR[15], AAC[16] and AAAC[17]). Overhead lines generally have lower capital and overall lifecycle cost than underground cables.

5.4.1 Quantity and life expectancy of distribution and LV lines

Asset	Construction Type	Quantity	Life Expectancy
Poles	Concrete	24,575	80 years
	Wooden	1,922	45 years
	Other	70	45 years
Cross Arms	Wooden/Steel	47,131	45 years
Conductors	22kV	570.6 km	80 years
	11kV	894.6 km	80 years
	Low Voltage (LV)	732.1 km	80 years

Table 5-10 Distribution and Low Voltage lines asset summary (asset quantity as at Sep-18)

5.4.2 Management approach

In our management of overhead lines, our primary focus is on safety, and particular attention is paid to those lines in areas in high risk special locations, such as around schools, playgrounds, public recreation spaces, commercial and high population density areas.

Due to risks identified and increasing failure rates associated with small diameter copper conductors (16mm^2 or 25mm^2) and ACSR conductor (Swan 20mm^2), we have extended our structured replacement programme to address both copper and Swan conductor risk in urban areas from 2017/18, with priority given to those around schools and public spaces, as well as in rural areas with repeat performance issues. Factors to consider are the fault frequency in the area, public safety risk (likelihood and consequence), as well as considering other network development needs to address capacity constraints.

Additionally, under the *Electricity (Safety) Regulations 2010*, we have to ensure that the structures that support our lines are capable of withstanding service loads. This requires us to inspect and where necessary test poles and other components and replace those found to be unsafe within specified periods. For condition assessment of both concrete and wooden poles we use visual assessment methods, and additionally for timber poles we use an ultrasonic scan method.

[15] Aluminium Conductor Steel Reinforced
[16] All Aluminium Conductor
[17] All Aluminium Alloy Conductor

We also have to make sure our lines do not get affected by trees, third parties working on and around our network, and high loads travelling along roads.

Counties Power recognised that service line ownership, and the range of issues relating to service lines from a safety, reliability and customer service perspective have been a long-term industry issue. Initial assessment indicated that there are over 1,000 private HV lines (‘service lines’) on our network. A change in our ownership policy came into effect in January 2018 for Counties Power to own new HV lines on private land, and to address existing private HV lines through more systematic clarification of ownership and adoption of private HV lines in a staged and risk assessed approach over the following 2 years. This will increase the number of poles and our requirements for pole renewal and maintenance. An additional annual budget provision of $1.5 million in the renewal programme and $200,000 per annum in the maintenance programme has been allowed for in the budget.

5.4.3 Distribution and LV conductors

Age profile

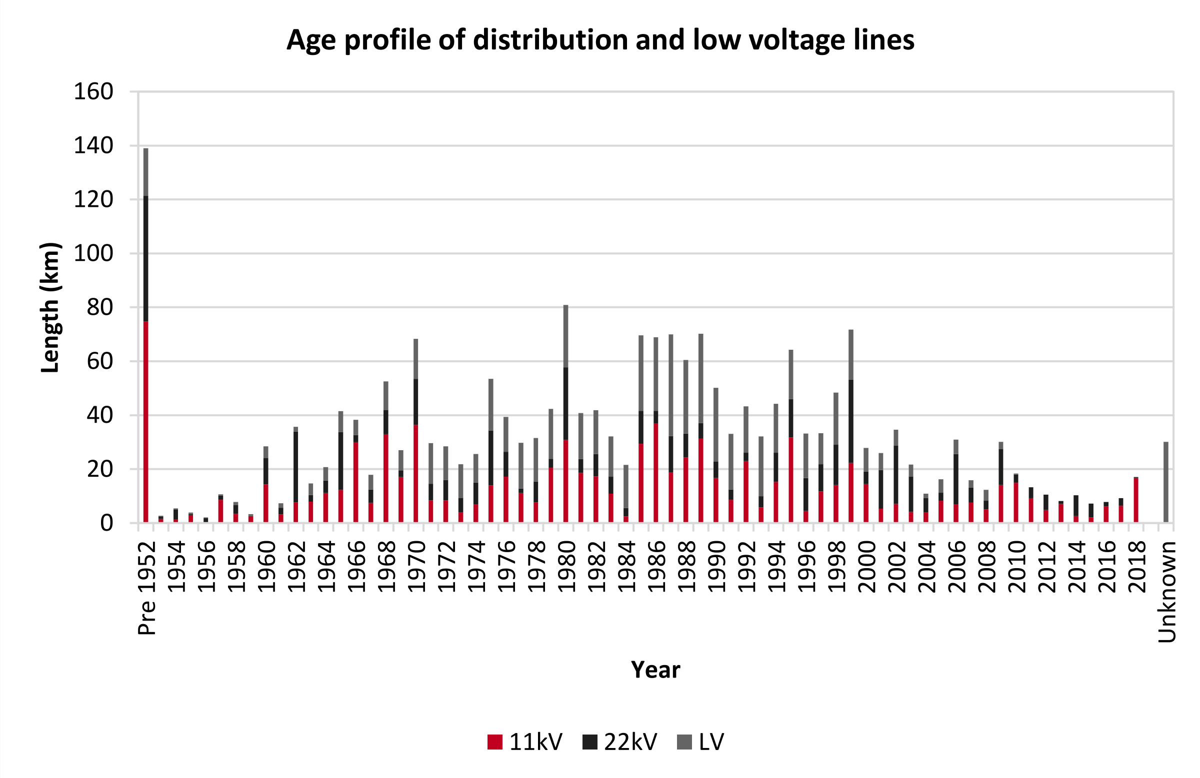


Figure 5-8 Age profile of Distribution and Low Voltage Lines

Inspection and maintenance practices

There are few components of overhead lines requiring routine servicing, and issues are identified through periodic inspections of overhead lines and their support structures, or from failure mode analysis. These surveys include assessing the condition of poles and towers, cross arms, connectors and clamps, clearances from trees, clearances from other components as well as clearance from the ground and buildings.

Defects are noted and addressed in accordance with their priority, particularly when it presents a hazard for public safety or the reliable operation of the network.

Our inspection and maintenance cycles for Distribution and Low Voltage lines are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly
Vegetation Survey	Inspection	Area Specific

Table 5-11 Inspection and maintenance cycles for Distribution and Low Voltage Lines

Corrective Maintenance is undertaken as required when defects have been identified and includes such activities as cross arm and insulator replacement, pole straightening, conductor resagging, fitment of stay wires, spacers, and possum guards.

We undertake Vegetation Management in accordance with the *Electricity (Hazards from Trees) Regulations 2003*.

The regulations define "zones" around power lines which must be kept clear of vegetation. However, an increasing number of tree vs line events are from trees that are outside of the "cut" zone but present a fall risk. These are noted as being "out of zone trees". The issue of responsibility for these trees and the risks they pose to lines has been raised by the power industry with the regulators as whilst it is considered the lines companies are best placed to identify and resolve such issues there is currently no regulatory mechanism to allow for the recovery of costs for such work. We are proactively identifying such trees and working with the owners to resolve issues.

Renewal programme

There are some sections of overhead line on the west coast where ACSR conductor has deteriorated prematurely due to the corrosive west coast conditions. These line lengths are relatively short, and their condition is being monitored. They are replaced by AAC or AAAC conductor where necessary.

We have two replacement programmes for small diameter overhead conductors which have reached end of life and are presenting safety and reliability issues due to their condition, with increasing failure rates year on year. These two types are copper conductors (16mm^2 to 35mm^2) of which we have a total length of 226 km and Swan ACSR (20mm^2) of which we have around 349 km. The forecast costs are based with the currently identified replacement solution and in some locations, we may consider undergrounding as an option where there are significant safety, reliability or community benefits by undergrounding.

Copper conductor replacement programme

A prioritised programme of replacing copper conductor commenced in 2016/17 in areas where there is elevated public risk, where there have been identified repeat failures or performance issues and where there is no other capacity or development need for replacement over the next 3 years.

The overhead copper conductor renewal projects identified for the next 3 years are as follows:

Feeder	Substation	Area	Financial Year	Length (km)	Cost
Waiau Pa (Clarks Beach)	Karaka	Urban	2020	2.9	$1,450,000
Otaua (Maioro Rd)	Maioro	Rural	2020	3.9	$600,000
Glen Murray (Woodleigh Rd)	Pukekawa	Rural	2021	1.1	$180,000
Pukekohe East (Tuhimata Rd)	Pukekohe	Rural	2021	2.7	$550,000
Railway (Racecourse)	Pukekohe	Rural	2021	0.9	$180,000
Waiuku West	Waiuku	Urban	2022	0.5	$320,000
Pukekohe East (Coulston Rd)	Pukekohe	Rural	2022	1.2	$250,000
Kaiaua (Miranda Rd)	Mangatawhiri	Rural	2022	7.9	$1,417,000

Feeder	Substation	Area	Financial Year	Length (km)	Cost
				Total:	$4,947,000

Table 5-12 Prioritised programme of replacing copper conductor

A further $18 million is forecast to be spent for the remainder of the planning period (2023-2029) to replace copper HV conductors.

Swan conductor replacement programme

A prioritised programme of replacing Swan ACSR conductor commenced in 2017/18 in areas where there is elevated public risk, where there have been identified repeat failures or performance issues and where there is no other capacity or development need for replacement over the next 3 years.

Overhead Swan conductor renewal projects identified for the next 3 years are as follows:

Feeder	Substation	Area	Financial Year	Length (km)	Cost
Otaua (Maioro Rd)	Maioro	Rural	2020	6.1	$900,000
Pukekohe Hill	Pukekohe	Urban	2021	0.5	$300,000
Glen Murray (Woodleigh Rd)	Pukekawa	Rural	2021	0.5	$80,000
Church Corner	Tuakau	Urban	2021	1.2	$250,000
Red Hill	Opaheke	Urban	2021	3.5	$750,000
Pukekohe West	Pukekohe	Urban	2022	1.8	$1,000,000
Tuakau	Tuakau	Urban	2022	1.0	$190,000
Waiuku West	Waiuku	Urban	2022	2.0	$370,000
River Road	Tuakau	Urban	2022	3.5	$640,000
				Total:	$ 4,480,000

Table 5-13 Prioritised programme of replacing ACSR (Swan) conductor

A further $21.5 million is forecast to be spent for the remainder of the planning period (2023-2029) to replace Swan conductors.

HV and LV line replacement programmes

In addition to the conductor replacement programmes above, it has been identified that replacement of other overhead lines in poor condition across the network will be required. These were identified from asset condition surveys and post fault investigations. The identified projects for high voltage line replacement in the next 3 years include:

Location	Area	Financial Year	Length (km)	Cost
Victoria Ave, Waiuku (Stage 2)	Urban	2020	0.6	$650,000
Norfolk Rise, Waiuku	Urban	2021	0.3	$240,000
Jericho Rd, Harrisville	Rural	2021	0.2	$150,000
Kaiaua Road, Kaiaua	Urban	2022	1.0	$300,000
			Total:	$1,340,000

Table 5-14 Prioritised programme of HV overhead conductor replacement

The identified low voltage conductor replacement from 2018/19 are prioritised based on condition and urban locations. The identified areas for low voltage line replacement for the next 3 years include:

Location	Area	Financial Year	Length (km)	Cost
Valley Road, Waiuku	Urban	2020	0.3	$120,000
SH22, Paerata	Urban	2021	1.6	$550,000
Queen St, Pukekohe	Urban	2021	0.4	$350,000
			Total:	$1,020,000

Table 5-15 Prioritised programme of LV overhead conductor replacement

A further $2.26 million is forecast to be spent for the remainder of the planning period (2023-2029) to replace low voltage conductors.

We have made an annual budget allocation for other urban overhead network replacement of $300,000 to address other issues identified in subsequent years, as well as an annual allowance of $100,000 to address other safety critical issues such as low road crossings and clearances.

5.4.4 Poles

We have 26,567 poles in our distribution system. The majority are concrete poles, as these have been predominantly installed since the mid-1940s, with the remainder made up of hardwood, softwood and other types such as iron rail or steel.

Age profile

The age profile of our distribution and LV poles is shown in Figure 5-9. The age profile portrays a network that has undergone significant expansion and replacement over the last 25 years. The life expectancy is 80 years for concrete poles and 45 for wooden poles.

The quantities and age profile shown is based on distribution and LV poles that we have records of in our system as being Counties Power owned. A pole survey focused on the ownership and usage of all poles in our service area which support electrical equipment was completed in 2017. The survey identified over 2,200 poles that we did not previously have records of but are deemed to be owned by us. With the increased number of poles, our requirements for pole renewal have increased and we increased the budget provision in the renewal and maintenance programmes to cover the additional assets.

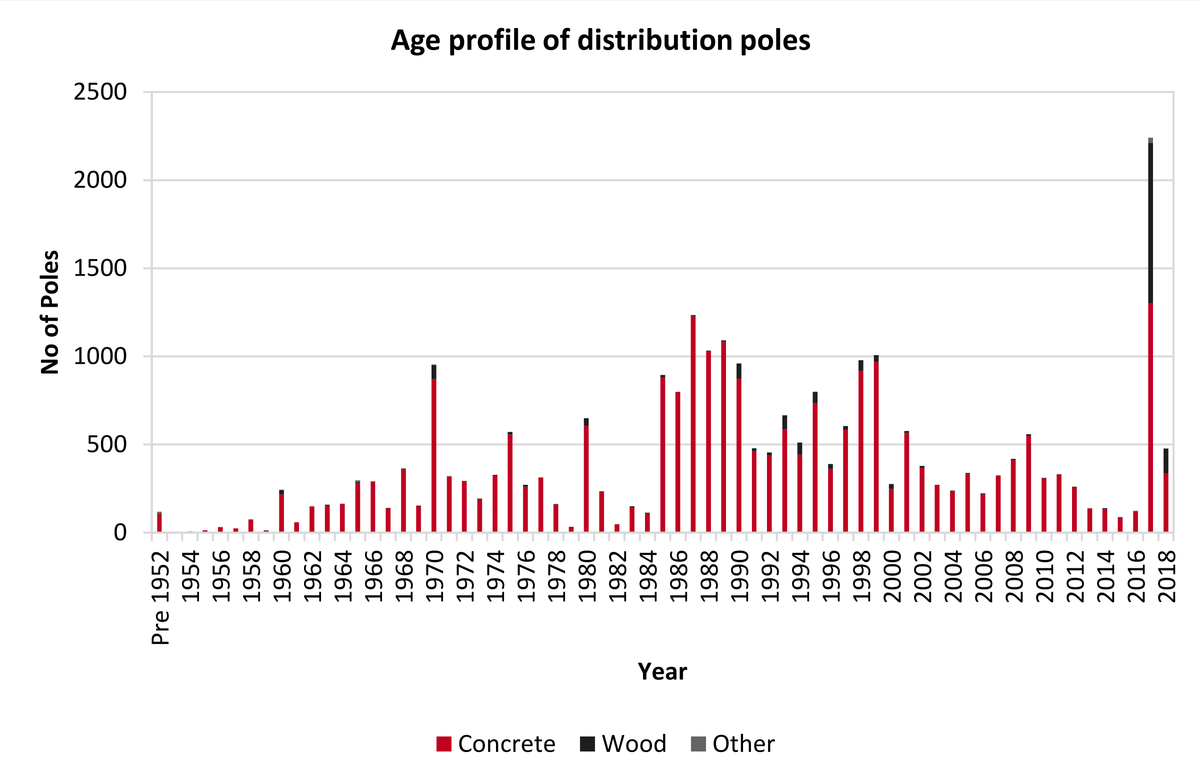


Figure 5-9 Age profile of Distribution and Low Voltage Poles[18]

Inspection and maintenance practices

Our inspection and maintenance cycles for Poles are shared with Overhead Lines (previous section) and are:

Activity	Type	Frequency
Overhead line feeder patrol	Inspection	Annual
Detailed Pole and Line Condition Assessment	Inspection	5 yearly

Table 5-16 Inspection and maintenance cycles for overhead lines

Renewal programme

There is a known issue with concrete poles manufactured around the 1960s not attaining their full life expectancy due to high levels of corrosion on the internal steel reinforcing material. This age group represents approximately 2.5% of our total poles population. We are monitoring the condition of these poles and they will be replaced when necessary but are expecting a higher than average replacement rate. These will be replaced following identification during routine inspections.

Based on age profiles and standard asset lives, a large number of concrete poles are now at end of their typically expected life, however their condition does not yet justify replacement.

[18] Poles identified from the pole survey in 2017 were given a default date of 1 January 2017.

Hardwood poles have known issues with ground line and below ground rot which leads to a deterioration of the strength of the pole. Some softwood poles have been found to not reach their full expected life and generally require replacement after approximately 30 years of service.

Specific replacement programmes are planned to replace hardwood, softwood and iron rail type poles from the network as these present safety risks if left in poor condition. Many of these are replaced as part of area line rebuild work, but in some cases individual replacement will be required. Table 5-17 shows the quantity of each type of pole expected to require replacement during the planning period based on age profiles. These will be subject to a targeted condition assessment programme, with replacement driven from poor condition scores and prioritised by safety and network risks.

Type	Quantity	Estimated cost to replace
Hardwood	347	$3.5 m
Softwood	1,575	$12.6 m
Iron Rail	56	$0.5 m
Total	1,978	$16.6 m

Table 5-17 Number of poles expected to require replacement during the planning period based on age profiles

An increased number of defects have been identified over the past year on poles and overhead hardware, arising from routine inspections. We have allowed an annual budget to replace the worst condition poles and overhead hardware on the network and the adoption of existing private HV lines over the planning period, with an allocation of $3.35 million in 2020, decreasing to $3.3 million from 2022 to 2029.

Poles are also replaced proactively when found to have poor structural condition, or reactively as a result of vehicle or storm damage.

We expect to replace around 250 poles and overhead hardware at over 360 pole sites per year under the overhead renewal programme and replace another 30 to 50 poles under other programmes of work.

5.4.5 Cross arms

We have over 47,131 cross arms installed on our poles supporting overhead lines. Multiple cross arms may be installed on a single pole depending on the function of each pole (e.g. whether the pole carries a single voltage or multiple voltages). Figure 5-10 shows the age profile of our cross arms. As they are installed at the same time as the poles, they share a similar age profile. The exception to this is where wooden cross arms are installed on concrete or steel poles. Wooden cross arms have a shorter life expectancy compared to concrete or steel poles so would require replacement at shorter intervals. Increasingly, steel cross arms have been used to achieve longer service lives compared to wooden cross arms.

Age profile

The age profile of our cross arms is shown in Figure 5-10. The average age of our cross arms and conductors are slightly lower than the average age of our poles due to re-conductoring on existing poles.

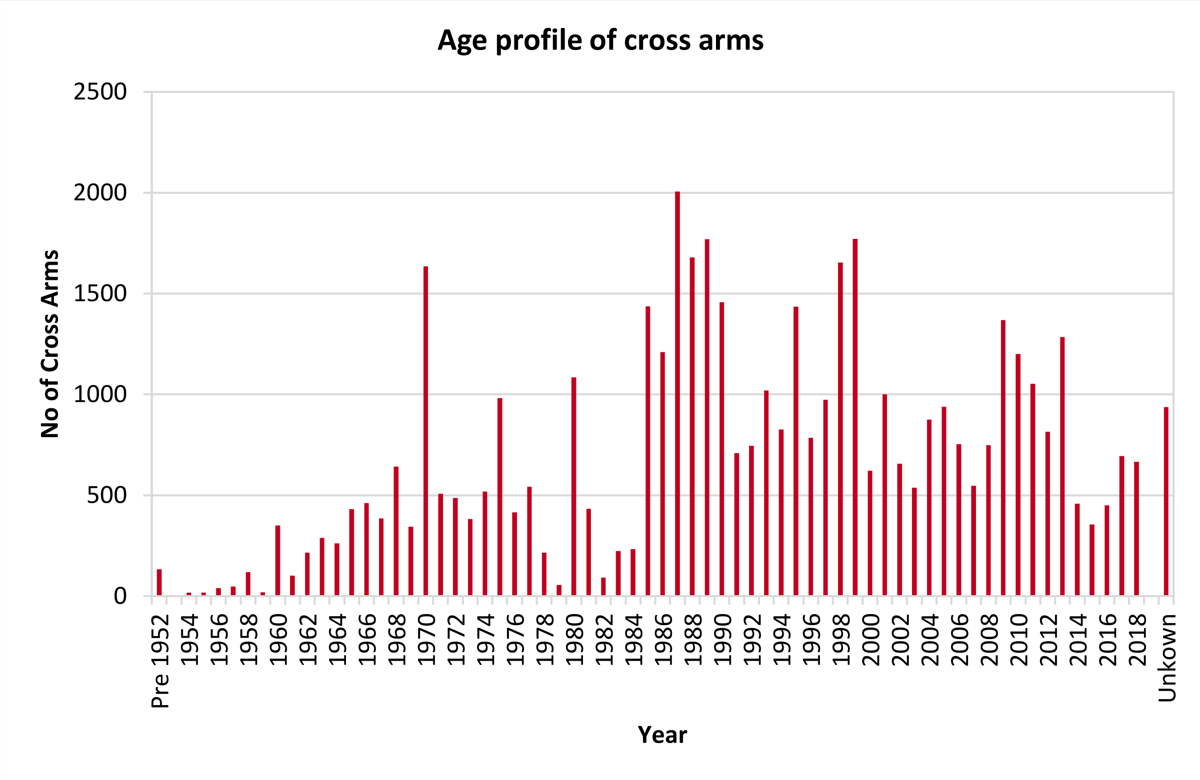


Figure 5-10 Age profile of Cross Arms

Inspection and maintenance practices

Cross arms are inspected as part of the overhead line condition surveys undertaken annually. Defects are raised for those cross arms which are no longer serviceable, and they are scheduled for replacement.

Renewal programme

We replace our cross arms that are near the end of their life once identified through routine inspections as opposed to having a specific programme for replacement based on age. Cross arms are also replaced in conjunction with pole replacement or re-conductoring projects.

5.4.6 Summary of distribution and LV lines expenditure forecast

Expenditure Forecast ($000)	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Capital Expenditure										
Overhead Renewals	3,350	3,350	3,300	3,300	3,300	3,290	3,300	3,300	3,300	3,300
Copper Replacement Programme	2,050	910	1,990	2,500	2,460	2,210	2,410	2,600	2,640	3,150
Swan Replacement Programme	900	1,380	2,200	1,390	2,950	3,750	4,050	3,530	2,630	3,230
HV Feeder section replacement	650	390	300	300	300	300	300	300	300	300
Urban LV Replacement	120	550	350	320	240	450	260	250	380	300
Overhead Safety Compliance	100	100	100	100	100	100	100	100	100	100
Capital Expenditure Total	7,170	6,680	8,240	7,910	9,350	10,100	10,420	10,080	9,350	10,380
Operational Expenditure										
Distribution poles and crossarms	950	950	950	950	950	950	950	950	950	950
Distribution conductor	70	70	70	70	70	70	70	70	70	70
Fault indicators and Earthing	20	20	20	20	20	20	20	20	20	20
Operational Expenditure Total	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040

Table 5-18 Distribution and Low Voltage Lines expenditure forecast summary

5.5 Distribution and LV cables

In addition to our Distribution and LV lines we have Distribution and LV cables. Underground cables have a higher capital and overall lifecycle cost than overhead lines but have higher reliability and lower ongoing maintenance costs.

Most new construction in the urban area uses underground cables as District Plan rules restrict the installation of new poles and overhead lines, and most land developers require electricity to be supplied underground for new subdivisions.

Our distribution cables (22kV and 11kV) are of XLPE or PILC construction. Our 400V cables are of XLPE, PVC and PILC.

We have 151.2 km of 22kV cables, 75.6 km of 11kV cables and 684.7 km of 400V LV cables. We also have 47.8 km of street lighting cable which is in a separate trench from our 400V LV cables, however there are significant lengths of street light circuits installed with LV cables which are not recorded on early plans and we do not know the length of these circuits.

5.5.1 Quantity and life expectancy of distribution and LV cables

Asset	Construction Type	Length in KM	Life Expectancy
Distribution Cables 22kV	XPLE	151.2	55 years
Distribution Cables 11kV	PILC	19.9	70 years
	XLPE	55.7	55 years
LV Cables	PVC	86.9	55 years
	XLPE	533.7	55 years
	Other	64.0	70 years
Street Light Cables	PVC	43.8	55 years
	XLPE	1.7	55 years
	Other	2.2	70 years

Table 5-19 Distribution and Low Voltage Cables asset summary (asset quantity as at Sep-18)

5.5.2 Management approach

Distribution and Low Voltage cables are generally reliable and maintenance free, and therefore the approach we take to managing these assets is to either repair or replace on failure. We don't have any first generation XLPE cable remaining on the network, which has known type issues and experienced premature failure on many networks due to water treeing[19].

In some parts of the network there is undersized 11kV cabling, particularly around Papakura South and Waiuku area which will be replaced as part of capacity augmentation projects over time. There are also cast metal cable termination boxes on poles which when identified will be replaced as they are known to fail due to water ingress.

5.5.3 Distribution cables

Age profile

Figure 5-11 shows the age profile of our distribution cables. The average age of our XLPE cable is 9 years and the average age of our PILC cable is 34 years.

The life expectancy of XLPE cables is 55 years and PILC cables is 70 years with the first replacement expected beyond this planning period.

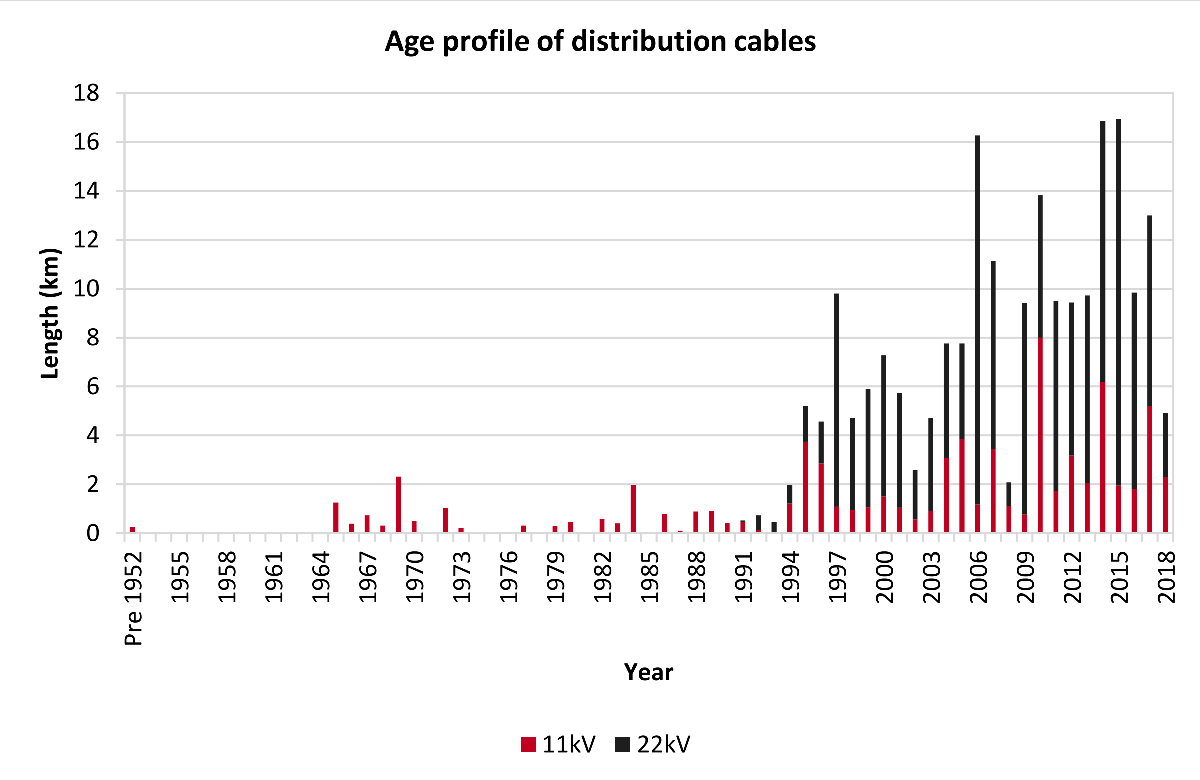


Figure 5-11 Age profile of Distribution Cables

[19] Water treeing is a form of insulation degradation observed on early XLPE cables

Note since 1994 we have only installed 22kV rated cables, the above chart shows the voltage they currently operate at.

Inspection and maintenance practices

Underground distribution cables are not proactively inspected or tested as they are generally maintenance free. Cable terminations and risers on poles are inspected as part of overhead line condition assessment surveys, and repair work is undertaken where defects are found. Cable terminations on ground mounted switchgear are not easily inspected, however the use of thermal imaging and partial discharge location equipment assists in identifying deteriorating cable terminations in these locations.

Renewal programme

There is no proactive renewal programme for this asset type as our management strategy is to replace upon failure or when the level of reliability becomes unacceptable, however an allowance is made each year for replacement of cable sections found to be faulty. We have made an allowance of $150,000 in 2020, increasing to $300,000 from 2024 to address these replacements.

In addition, when we replace RMU switchgear, the cables are also replaced with 22kV rated cables ready for future network development.

5.5.4 LV cables

Age profile

Figure 5-12 shows the age profile of our LV cables in our system which has an average age of 12 years.

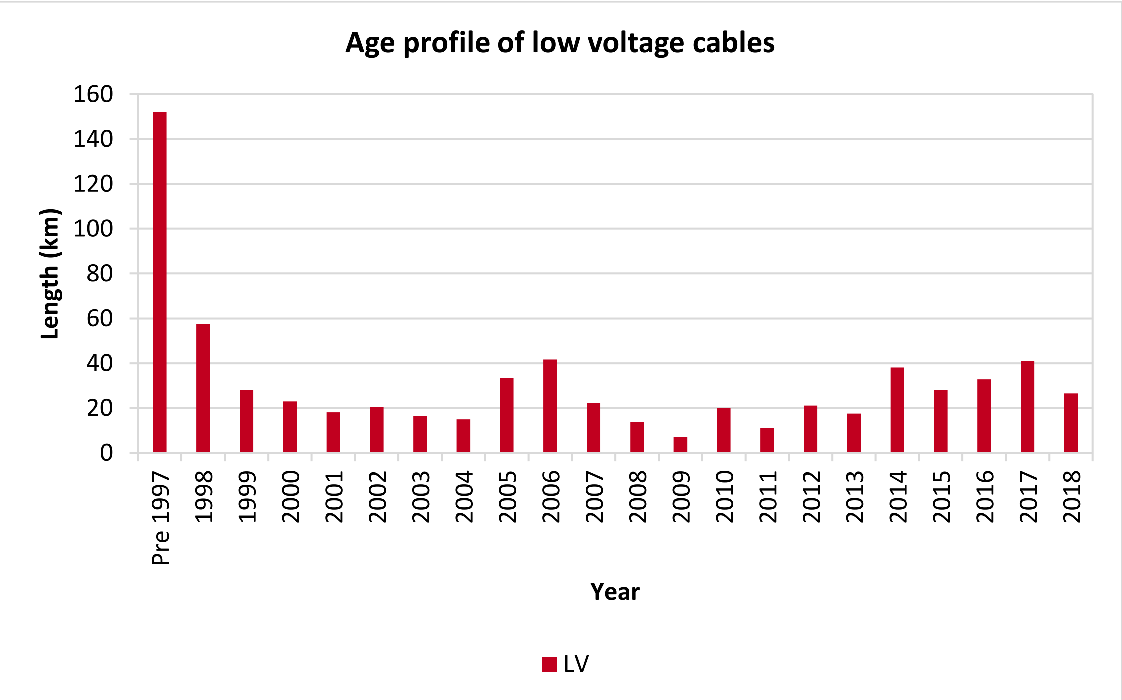


Figure 5-12 Age profile of Low Voltage cables

Inspection and maintenance practices

Underground LV cables are not proactively inspected or tested as they are generally maintenance free. Cable terminations and risers on poles are inspected as part of overhead line condition assessment surveys, and repair work is undertaken where defects are found.

Renewal programme

There is no proactive renewal programme for this asset type, however an allowance of $150,000 is made each year for replacement of cable sections found to be faulty.

5.5.5 LV Pillars and Pits

We have 13,014 LV Pillars and Pits in our network, connected to LV cables. These generally accommodate fusing for consumer supply points, but some pillars are used as link pillars between two adjacent low voltage circuits. Pits are not widely used and avoided where possible in new build situations.

Age profile

Figure 5-13 shows the age profile of our LV Pillars. The average age of our LV Pillars is 16 years.

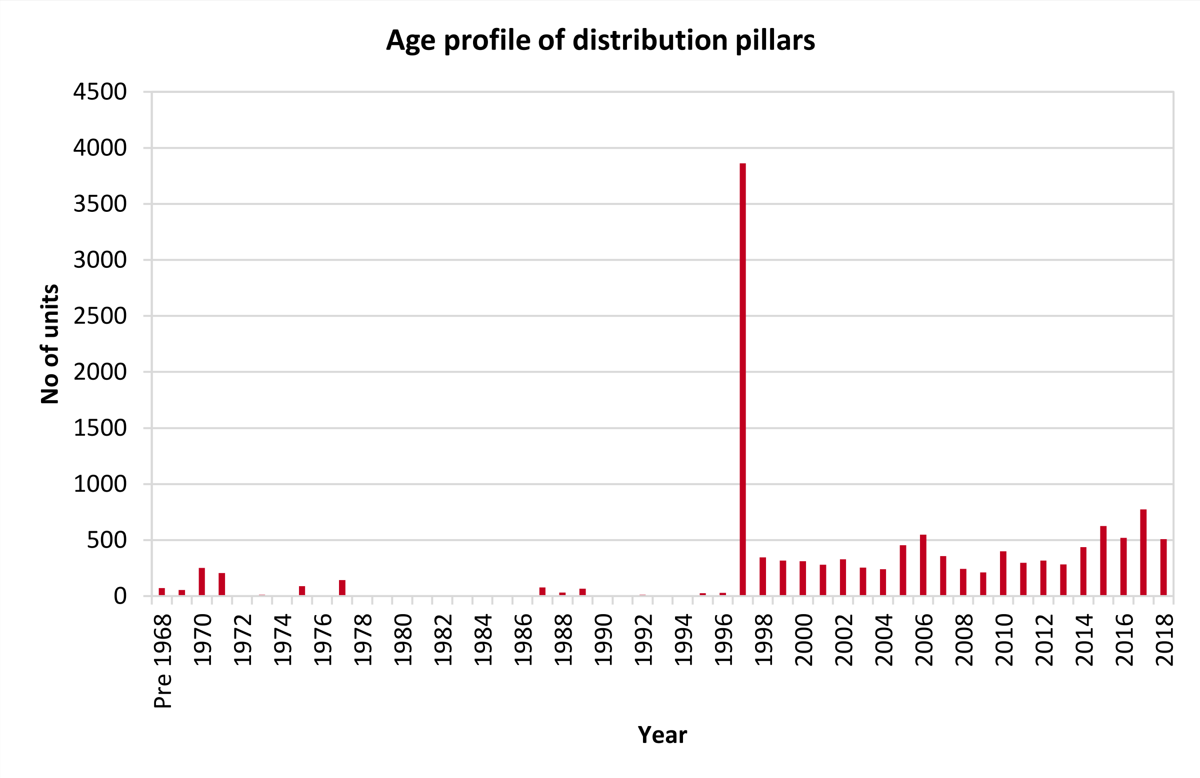


Figure 5-13 Age profile of LV Pillars[20]

[20] *Note the peak in 1997 represents a default setting in the database*

Inspection and maintenance practices

We carry out 5 yearly visual inspections and thermographic tests on our LV Pillars to ensure they are safe and secure, and that the components are not overheating which is a common mode of failure.

Corrective maintenance is used to address minor issues such as insecure lids, hot connections, or alignment and siting issues (leaning, etc.). Vehicle damage is common, and entire pillar replacement is the usual remedy depending on the nature of damage.

Renewal programme

There are no specific programmes for pillar replacement, however an allocation is made in the annual plan for corrective repairs and replacements of damaged or defective pillars.

5.5.6 Summary of distribution and LV cables expenditure forecast

Expenditure Forecast ($000)	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Capital Expenditure										
Distribution and LV cables Renewal	150	150	150	150	300	300	300	300	300	300
LV Pillar Renewal	180	190	200	210	210	220	230	240	250	260
Capital Expenditure Total	330	340	350	360	510	520	530	540	550	560
Operational Expenditure										
Distribution and LV cables	150	150	150	150	150	150	150	150	150	150
LV Pillars	140	140	140	140	140	140	140	140	140	140
Operational Expenditure Total	290	290	290	290	290	290	290	290	290	290

Table 5-20 Distribution and Low Voltage cables expenditure forecast summary

5.6 Distribution Substations and Transformers

Distribution substations accommodate transformers which step down higher distribution voltages (22kV or 11kV) to low voltage (400V/230V) for distribution to consumers, along with other equipment such as high voltage fusing, low voltage fusing and earth grids.

Distribution switching stations accommodate switchgear such as ring main units or circuit breakers and are used to control and isolate the network by switching sections of distribution feeders, and to supply and protect transformers. This enables a section of the network to be de-energised for maintenance work, or to isolate faulted sections of the network in order to minimise the impact of faults.

Specially designed 22/11kV transformers connect our 11kV network to our 22kV network and to enable consideration of upgrading to 22kV as one of the options to address identified capacity and voltage constraints in the future. Upgrade to 22kV in each area is assessed on its individual merits, including evaluation of a range of alternatives.

5.6.1 Quantity and life expectancy of Distribution Substations and Transformers

Asset	Type	Quantity	Life Expectancy
Distribution Transformers	Pole mounted distribution transformers	3,145	45 years
	Ground mounted distribution transformers	830	45 years
22/11kV Transformers		47	45 years

Table 5-21 Distribution assets summary (asset quantity as at Sep-18)

5.6.2 Management approach

Public safety is a key driver of the maintenance programme for transformers and ground mounted substations, in particular the security of the units and ensuring members of the public cannot come into contact with live parts. Likewise, protecting the environment is a concern and making sure oil leaks do not occur due to corrosion or damage to tanks.

Some types of equipment, in particular early kiosk type substations have restricted operating space, and live parts, and these require outages to work safely in them. Where justified, these are replaced with modern alternatives.

Transformers are generally low maintenance, requiring little routine servicing, so the maintenance programme is inspection based, with corrective actions taken where required.

In some parts of our network, particularly within 10km of the coast, transformers do not reach their normal service life and are likely to be replaced 10 years earlier than in other locations due to corrosion of the tank and fittings.

5.6.3 22/11kV auto transformers

We have 47 22/11kV auto transformers, 25 are ground mounted and 22 are pole mounted units.

Figure 5-14 shows the age profile of our 22/11kV auto transformers. The average age of these transformers is 12 years.

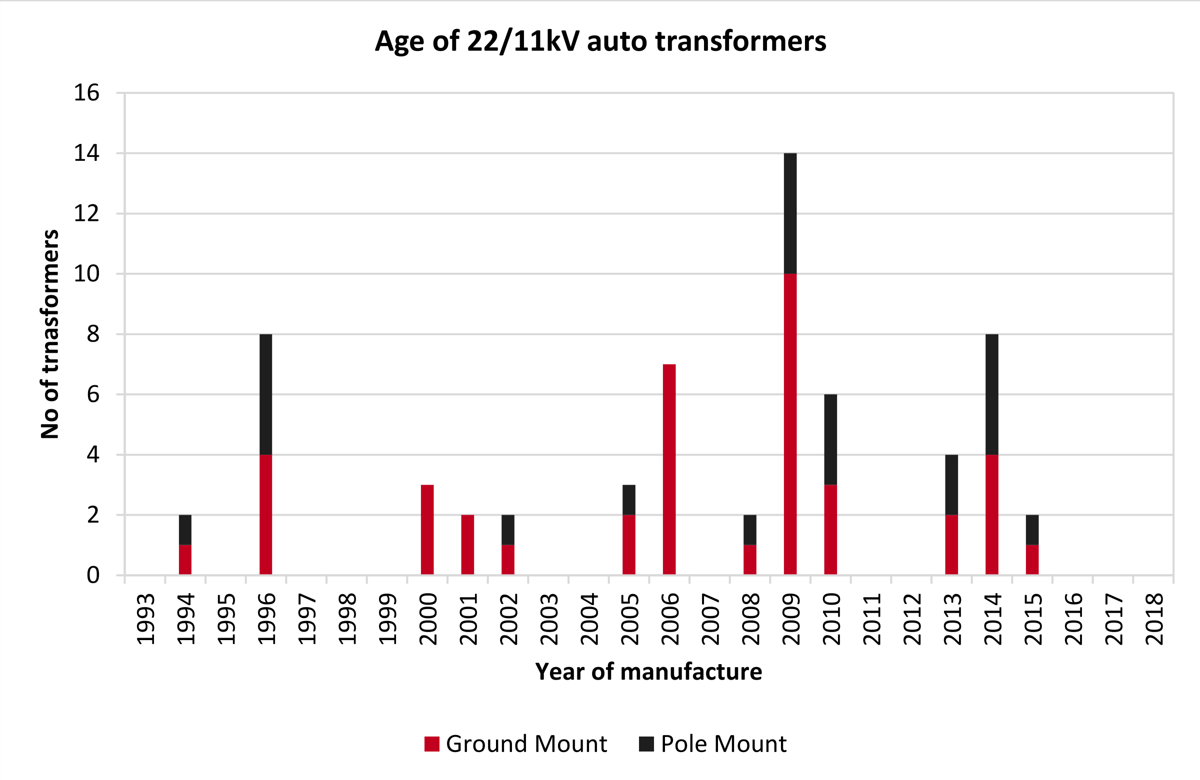


Figure 5-14 Age profile of 22/11kV transformers

5.6.4 Distribution transformers

We have 3,145 pole mounted distribution transformers, 1,163 on the 22kV network and 1,982 on the 11kV network.

Figure 5-15 shows the age profile of our pole mounted distribution transformers. The average age of our 22kV pole mounted transformers is 10 years and our 11kV pole mounted transformers is 28 years. The significant investment made over the last 20 years was driven by a combination of active replacement programme of older transformers in poor condition and development of our 22kV distribution network.

We have 247 pole mounted transformers that are older than the normal expected life of 45 years. This represents 8% of our total pole mounted distribution transformer population.

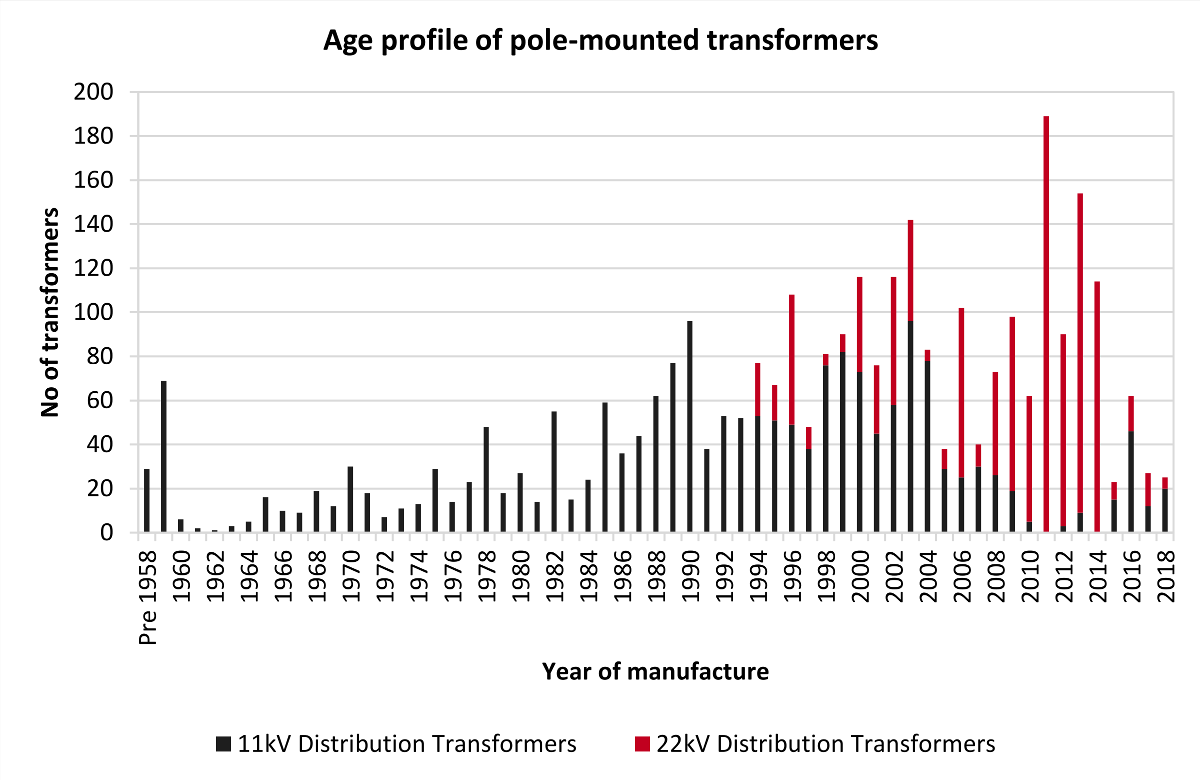


Figure 5-15 Age profile of Distribution pole-mounted transformers

We have 830 ground mounted distribution transformers, 547 on the 22kV network and 283 on the 11kV network.

Figure 5-16 shows the age profile of our ground mounted transformers. The average age of our 22kV ground mounted transformers is 12 years and the average age of our 11kV ground mounted transformers is 22 years. The significant investment made over the last 20 years was driven by significant network growth and development of our 22kV distribution network.

We have 31 ground mounted transformers that are older than the normal expected life of 45 years. This represents 4% of our total ground mounted distribution transformer population.

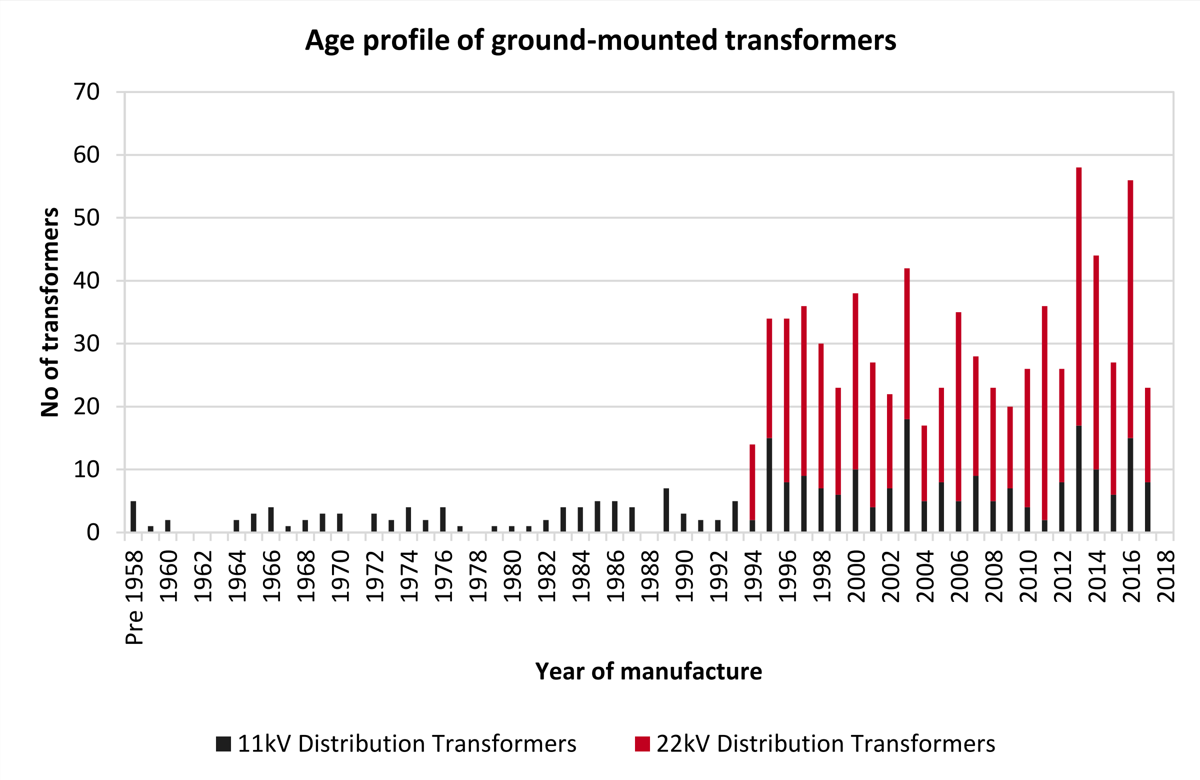


Figure 5-16 Age profile of Distribution ground-mounted transformers

Inspection and maintenance practices

We carry out safety checks, visual inspections and thermographic tests on our distribution transformers annually to ensure that the transformers remain safe, secure and defect free.

Activity	Type	Frequency
Transformer Inspection	Inspection	Annual

Table 5-22 Inspection frequency of distribution transformers

There is no routine servicing required, and any defects found during routine inspections are handled through the corrective maintenance programme.

Renewal programme

We plan to replace our transformers when their condition is unacceptable for continued service, where growth requires a capacity upgrade.

Based on age profiles and quantity in service, we expect to replace around 40 transformers per annum across planned upgrades (capacity and security), and as a result of condition assessment findings or reactive fault repairs. We have allowed $570,000 in the coming year for the renewal of transformers and associated equipment due to condition.

5.6.5 Expenditure Forecast

Expenditure Forecast ($000)	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Capital Expenditure										
Transformer Renewal Programme	750	650	660	750	660	400	450	450	450	450
Capital Expenditure Total	750	650	660	750	660	400	450	450	450	450
Operational Expenditure										
Distribution transformers	270	280	280	280	280	280	280	280	280	280
Operational Expenditure Total	270	280	280	280	280	280	280	280	280	280

Table 5-23 Distribution transformer expenditure forecast summary

5.7 Distribution Switchgear

Distribution switchgear is used to protect and isolate the network. Switchgear minimises the impact of outages arising from faults and planned work by sectionalising affected parts of the network.

On the overhead network, we use Air Break Switches (ABS), Gas Insulated Switches, Reclosers, dropout links and fuses, and spur line isolators.

On the underground network, we use Ring Main Units consisting of load break switches to provide isolation, and fuses or circuit breakers to protect transformers.

5.7.1 Quantity and life expectancy of Distribution Switchgear

Asset	Quantity	Life Expectancy
Ring Main Units	213	40 years
Air Break Switch	217	35 years
Gas Insulated Switch	130	35 years
Spur Line Isolator	1,491	35 years
Reclosers	31	40 years

Table 5-24 Distribution Switchgear assets summary (asset quantity as at Sep-18)

5.7.2 Management approach

Distribution Switchgear should be serviceable, free from defects and safe to operate at all times. It is a key component of operating the network safely and efficiently and providing necessary isolation of equipment. These devices are generally located in the public domain, so safety is our main consideration with regard to inspecting and maintaining these units.

Selection of good quality, low maintenance Ring Main Units (RMUs) has positioned us well, with little ongoing maintenance needed apart from routine safety checks.

A small number of older RMU types are unsafe to operate live, largely due to their age and condition, and this introduces operational restrictions and causes wider area outages than necessary. These units have been identified and will be replaced during the planning period.

A number of issues relating to overhead equipment have been identified, and programmes implemented to address these through the planning period, with priority given to higher risk issues and locations.

5.7.3 Ring main units

Ring Main Units are ground mounted switches for switching distribution cable rings and for connecting distribution transformers, generally through fused switches or circuit breakers, to the distribution network.

We have 213 RMUs in our distribution network, of which 192 are gas insulated, 7 are oil insulated, and 14 are air/resin insulated.

Age profile

Figure 5-17 shows the age profile of our RMUs. The average age of our RMUs is 11 years. We have 13 RMUs that are older than the normal expected life of 40 years. This represents 6% of our RMU population.

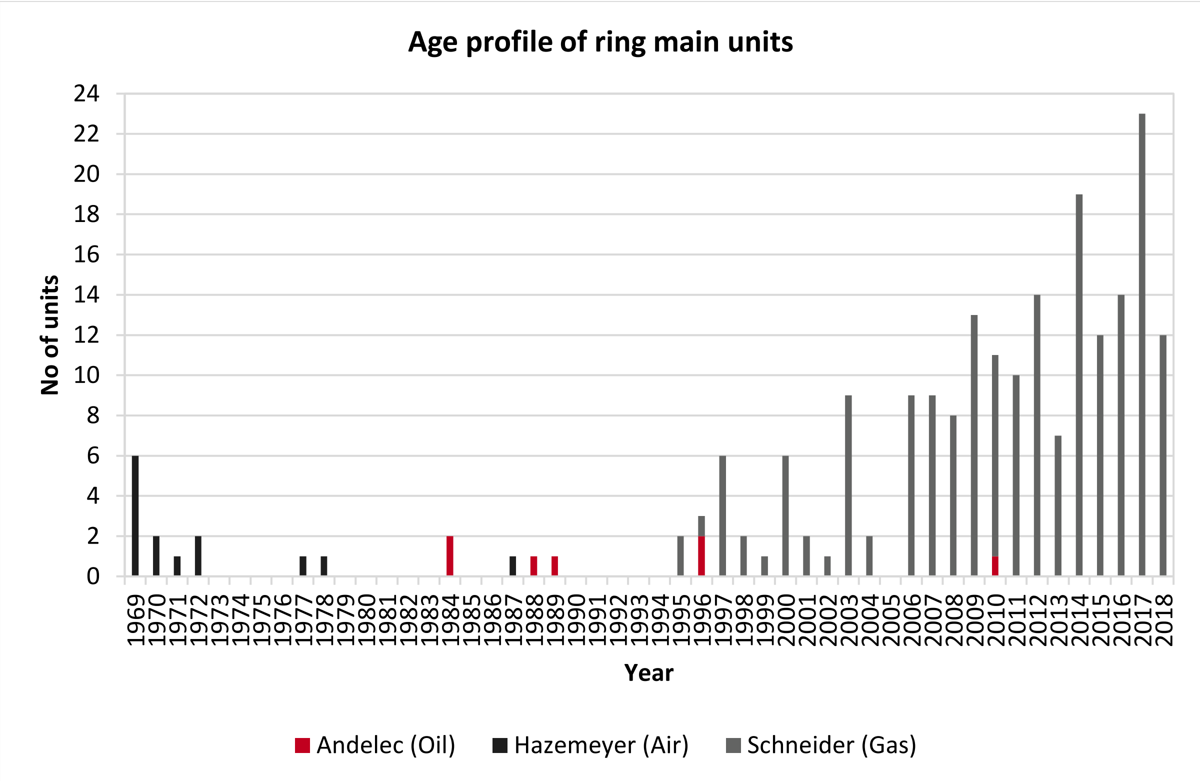


Figure 5-17 Age profile of Ring Main Units

Inspection and maintenance practices

We carry out annual visual inspections on our RMUs to ensure that they are safe, secure and free of defects.

The majority of the RMUs on the network are modern gas insulated Schneider RM6 units and require very little maintenance. Some of these units have automation fitted, which requires battery replacement every 5 years.

There are some types of RMU of older designs, particularly oil filled units such as Andelec/ABB SD series switchgear and Hazemeyer Magnefix which require higher levels of routine servicing to ensure they operate safely and correctly:

Activity	Type	Frequency
Ring Main Unit – Annual Inspection	Inspection	Annual
Ring Main Unit Maintenance – Oil Filled	Routine Maintenance	5 yearly
Ring Main Unit Maintenance – Hazemeyer	Routine Maintenance	5 yearly
Ring Main Unit Battery Renewal	Replacement	5 yearly

Table 5-25 Inspection frequency for RMUs

Renewal programme

We plan to replace all our air/resin insulated and oil filled RMUs within the next five years. There are two specific types of RMU which will be targeted for replacement by 2024, namely Hazemeyer Magnefix and Andelec SD-series. These replacements are driven by age, and condition. A standard procedure is in place to restrict operation of this equipment to a de-energised state to manage the operational risks.

There are 20 units identified for replacement, with an estimated replacement cost of $90,000 each, giving a total programme cost of $1.81 million. The associated costs for distribution cable and transformer replacement are covered in the respective renewal programmes.

Financial Year	Feeder	Andelec	Hazemeyer	Cost
2020	Papakura South	1	1	$340,000
2020	Racecourse		3	$190,000
2021	Papakura South	1	2	$300,000
2022	Beach Rd		4	$240,000
2023	Beach Rd	2	3	$400,000
2024	Racecourse		1	$180,000
2024	Drury Hills	2		$160,000
			Total	$ 1,810,000

Table 5-26 RMU replacement programme

Some of this replacement work will be undertaken in conjunction with network capacity and reinforcement projects.

5.7.4 Overhead distribution switchgear

Distribution switchgear consists of Reclosers, Air Break Switches (ABS), Gas Switches, and Isolators. They are used to protect and isolate the distribution network.

On our 22kV network, we have:

- 91 ABS, with an average age of 21 years. 16 ABS are older than the normal expected life of 35 years;
- 66 Gas Switches with an average age of 7 years. We have no 22kV gas switches older than the normal expected life of 35 years;

- 650 Isolators with an average age of 19 years. 58 Isolators are older than the normal expected life of 35 years; and
- 23 Reclosers and circuit breakers with an average age of 9 years. We have no 22kV Reclosers and circuit breakers older than the normal expected life of 40 years.

On our 11kV network, we have:

- 126 ABS, with an average age of 24 years. 23 ABS are older than the normal expected life of 35 years;
- 64 Gas Switches with an average age of 8 years. No Gas Switches are older than the normal expected life of 35 years;
- 841 Isolators with an average age of 21 years. 101 Isolators are older than the normal expected life of 35 years; and
- 8 Reclosers and circuit breakers with an average age of 15 years. No Reclosers and circuit breakers older than the normal expected life of 40 years.

Age profile

Figure 5-18 shows the age profile of our distribution switchgear and switches.

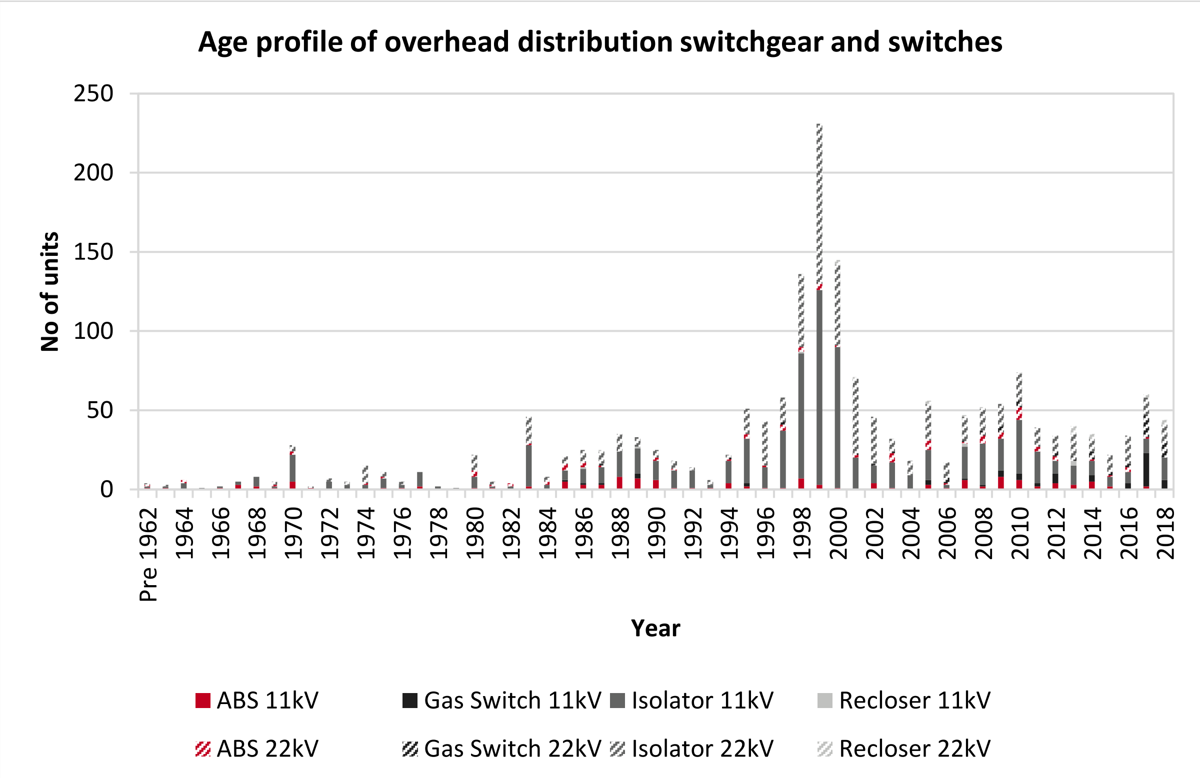


Figure 5-18 Age profile of Distribution switchgear and switches

Inspection and maintenance practices

Our inspection and maintenance cycles for distribution switchgear are:

Activity	Type	Frequency
Overhead Switch – Annual Inspection	Inspection	Annual
Air Break Switch Service	Routine Maintenance	5 yearly
Gas Switch Service	Routine Maintenance	5 yearly
Remote Switch Battery Renewal	Replacement	5 yearly
Recloser Service	Routine Maintenance	5 yearly
Recloser Battery Renewal	Replacement	5 yearly
Overhead Switch Earth Test	Routine Test	5 yearly

Table 5-27 Inspection and maintenance cycles for distribution switchgear

All overhead equipment is part of the annual overhead condition assessment programme, to identify any safety concerns or deterioration which can be addressed through the Corrective Maintenance programme. Overhead switchgear (except DDOs) is also subject to routine servicing to ensure it operates safely and correctly. Automated devices require their batteries to be replaced periodically, which is done in conjunction with routine servicing.

Renewal programme

Issues have been identified with the porcelain insulators on one particular type of air-break switch (ABS) and some types of HV 'drop out' style fusing which has led to a very high failure rate.

- A replacement programme commenced in 2017/18 to replace a total of 128 ABS within six years. A total of 68 ABS have been replaced in the first two years and another 60 ABS are planned to be replaced in the next four years. The replacement is prioritised based on the switch make and type, switch location and network function each switch provides. There are 34 units of one type of ABS with a particular common reliability issue which are to be replaced within the next three years, and other types of ABS are to be replaced within four years. The replacement programme uses new automated gas switches which provide several benefits in addition to addressing the identified condition issues. These include lower whole of life costs due to reduced maintenance requirements, automation to provide operational flexibility, and having capability for the future possibility of establishing a "self healing" network that automatically isolates a faulted section and re-routes power to the remaining areas; and
- Known types of HV 'drop out' style fusing will be identified and replaced where required, as well as some surge arrestors in coastal areas experiencing premature failure due to the harsh environment. These are handled as corrective replacements when found.

We do not forecast any renewal of reclosers during the planning period. However, more may be added for network performance improvements.

5.7.5 Summary of Distribution Switchgear Expenditure Forecast

Expenditure Forecast ($000)	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Capital Expenditure										
RMU replacement	1,720	1,140	920	960	1,120	480	480	480	480	480
Overhead switchgear replacement	600	600	480	420	450	480	480	480	480	480
Capital Expenditure Total	2,320	1,740	1,400	1,380	1,570	960	960	960	960	960
Operational Expenditure										
Ring main units	120	130	150	150	160	160	170	180	190	200
Overhead switchgear	250	260	260	260	260	260	260	260	260	260
Operational Expenditure Total	370	390	410	410	420	420	430	440	450	460

Table 5-28 Distribution switchgear expenditure forecast summary

5.8 Grid-scale battery storage system

Our first grid-scale battery storage system was commissioned at the Tuakau zone substation in mid-2017. This system consists of the isolating transformer, power converters, battery cells, monitoring and control systems, cooling and auxiliary supply systems.

In 2018 the system performed largely in line with expectations. We have identified further improvements and strategies which will be implemented in 2019 to better understand the system, particularly around control system integration.

Inspection and maintenance practices

Our proposed inspection and maintenance cycles for grid-scale battery system are:

Activity	Type	Frequency
Routine battery inspection	Inspection	6 monthly
Cooling and auxiliary systems	Routine Maintenance	6 monthly

Table 5-29 Inspection and maintenance cycles for grid-scale battery system

5.9 Other system fixed assets

5.9.1 Quantity and life expectancy of other network assets

Asset	Quantity	Life expectancy
Capacitor banks	29	55 years
Voltage Regulators	7	55 years
Protection relays	144	40 years
Load control relays	3,460	20 years
Ripple Injection plant	5	20 years
Auxiliary Battery Banks	27	8 years
Remote Terminal Unit	289	15 years

Table 5-30 Other system fixed assets summary (asset quantity as at Sep-18)

5.9.2 Capacitor banks and voltage regulators

Due to the electrical impedance of the line, the voltage at the end of feeders is lower than at the supply end, defined as voltage drop along the line. For long distribution feeders, this voltage drop can be significant resulting in unacceptably low voltages at the end of those feeders. We have installed voltage regulators partway on some of our long distribution feeders to maintain the correct voltage at the end of those feeders.

We have seven Voltage Regulators in our network operating at four sites. One is a three-phase unit, and three sites have two single phase units operating in an open-delta configuration.

Age profile

Figure 5-19 shows the age profile of our Voltage regulators. The average age of our voltage regulators is 16 years.

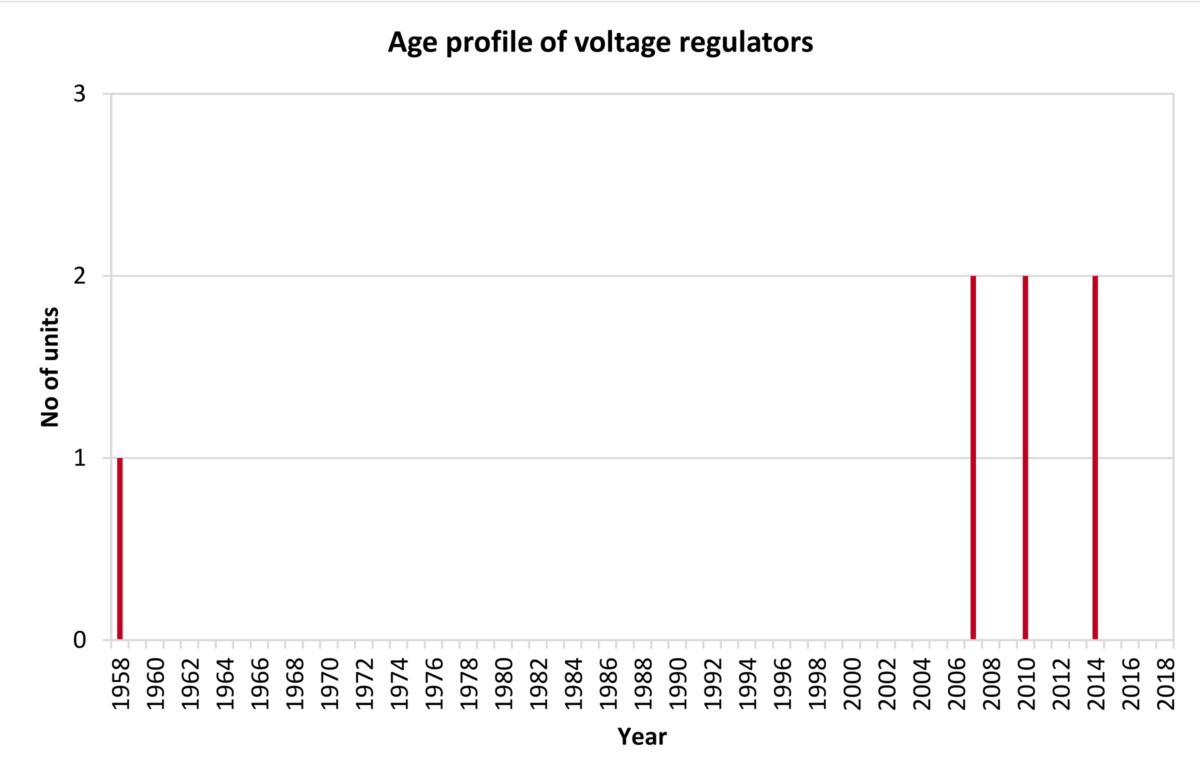


Figure 5-19 Age profile of Voltage Regulators

Capacitors provide power factor correction and help maintain the correct voltage by providing reactive support on long lines with high impedance.

We have 29 capacitors on our distribution network with installation dates ranging from 1998 to 2007. The average age of our capacitors is 18 years.

Figure 5-20 shows the age profile of our capacitors.

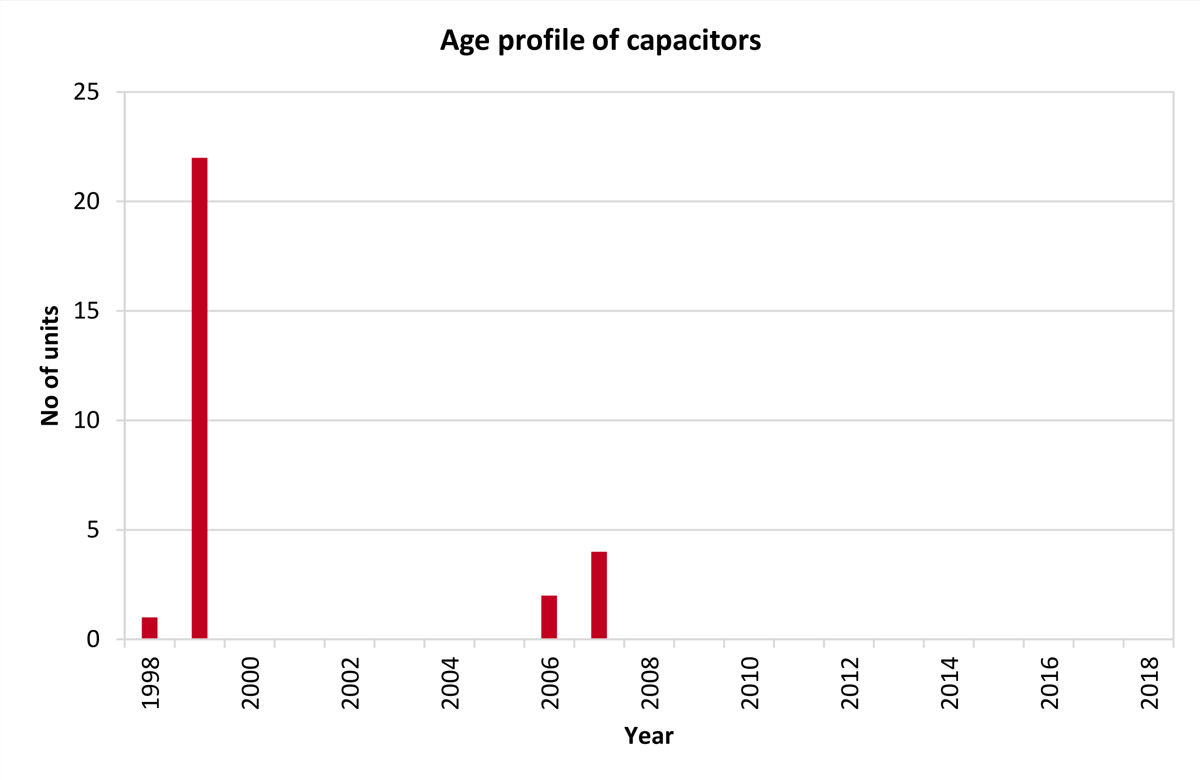


Figure 5-20 Age profile of Capacitors

Inspection and maintenance practices

Our inspection and maintenance cycles for our voltage support equipment are:

Activity	Type	Frequency
Capacitor Bank – Annual Inspection	Inspection	Annual
Voltage Regulator – Annual Inspection	Inspection	Annual
Voltage Regulator Servicing	Routine Maintenance	3 yearly

Table 5-31 Inspection and maintenance cycles for our voltage support equipment

Renewal programme

The majority of our voltage regulators and capacitors are in acceptable condition. There is an identified renewal need for the voltage regulator installed in 1958 on Glen Murray feeder to be replaced in 2019/20 at an estimated cost of $360,000. For parts of the network which have been converted to 22kV operation, some of the voltage regulators and capacitors can be redeployed to other areas to address identified voltage constraints.

5.9.3 Protection relays

Protection relays rapidly detect and initiate the operation of circuit breakers to isolate electrical faults to ensure safety of our staff and the public, and to protect equipment from short circuits and overloads.

We have 144 protection relays installed at our zone substations and at Transpower's Bombay and Glenbrook GXPs. The average age of our protection relays is 18 years.

Age profile

Figure 5-21 shows the age profile of our protection relays.

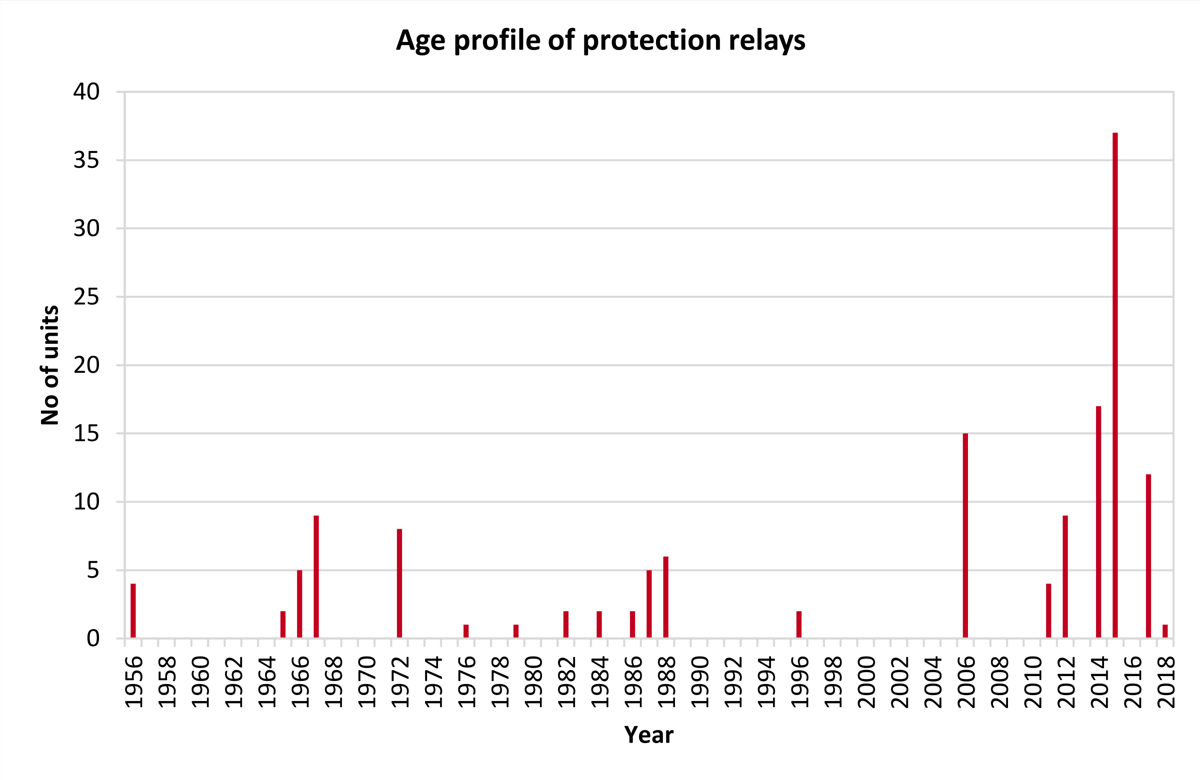


Figure 5-21 Age profile of protection relays

Inspection and maintenance practices

We test our protection relays every 3 years to ensure they operate correctly.

Renewal programme

We typically replace protection relays when we replace the primary plant which they relate to, for example replacement of feeder protection when we replace the corresponding circuit breakers. As a result of this, we include relay replacement in the cost of replacing the major primary plant. During this planning period we will replace end of life relays at Maioro, Waiuku, Mangatawhiri and Ramarama zone substations when we replace the switchboards and/or substations.

In some cases, we replace relays due to performance issues, or where we require different functionality. Our replacement programme for protection relays is planned for:

- Replacement of feeder protection relays at Karaka zone substation. These are approximately 18 years old and have been found to have emerging performance and reliability issues at the end of life (20 years). We have recovered spare relays to manage the reliability issues and plan to replace these relays in 2019/20 for an estimated cost of $320,000;
- Replacement of feeder protections relays at Maioro Substation in 2024/25 at an estimated cost of $240,000 (dependent on the major customer's future demand from the site); and

- The Electricity Authority issued an amendment to the Electricity Industry Participation Code (the Code) in 2017 which changes the nature of the AUFLS scheme and replaces it with the Extended Reserves scheme. Changes to the new system were to start in April 2018 and be completed by mid-2019. The Electricity Authority paused the project in October 2017 to assess options for more reliable delivery of the scheme, we will programme any required works once we receive advice on how the scheme will be changed. Based upon the specified requirements for implementation of this scheme, we will need to change some relays to provide the required functionality to meet new technical requirements. Any new relays we install before then will be compatible with the proposed requirements. We have allowed $300,000 for new relays in 2020/21, deferred from 2019/20 to reflect the latest update and uncertainty from the Electricity Authority.

5.9.4 SCADA and Communications systems

Our GE iFix SCADA system is performing in line with current business needs and will remain in service for the short term. However, we do plan to upgrade to a more modern ADMS SCADA system, which will enable us to utilise our smart meter network, and leverage on geospatial data for quick and reliable control of the Counties Power network. Requirements will be determined for investment in 2020/21.

We operate an analogue SCADA radio network, as well as a digital voice radio network, and have repeaters in five locations to provide coverage and redundancy. The digital voice network was installed in 2015 and is in very good condition. Our analogue SCADA radio equipment is also in good condition, however a communications network strategy is under development to determine the next phase of improvements. Some equipment replacement and new repeater sites is expected in the short to medium term following completion of that strategy.

We have 289 SCADA remote terminal units (RTUs) installed on our network with 14 located at Grid Exit Points and Zone Substations, and 275 installed on switchgear and devices across the network to provide remote control and indication. An age profile is shown in Figure 5-22.

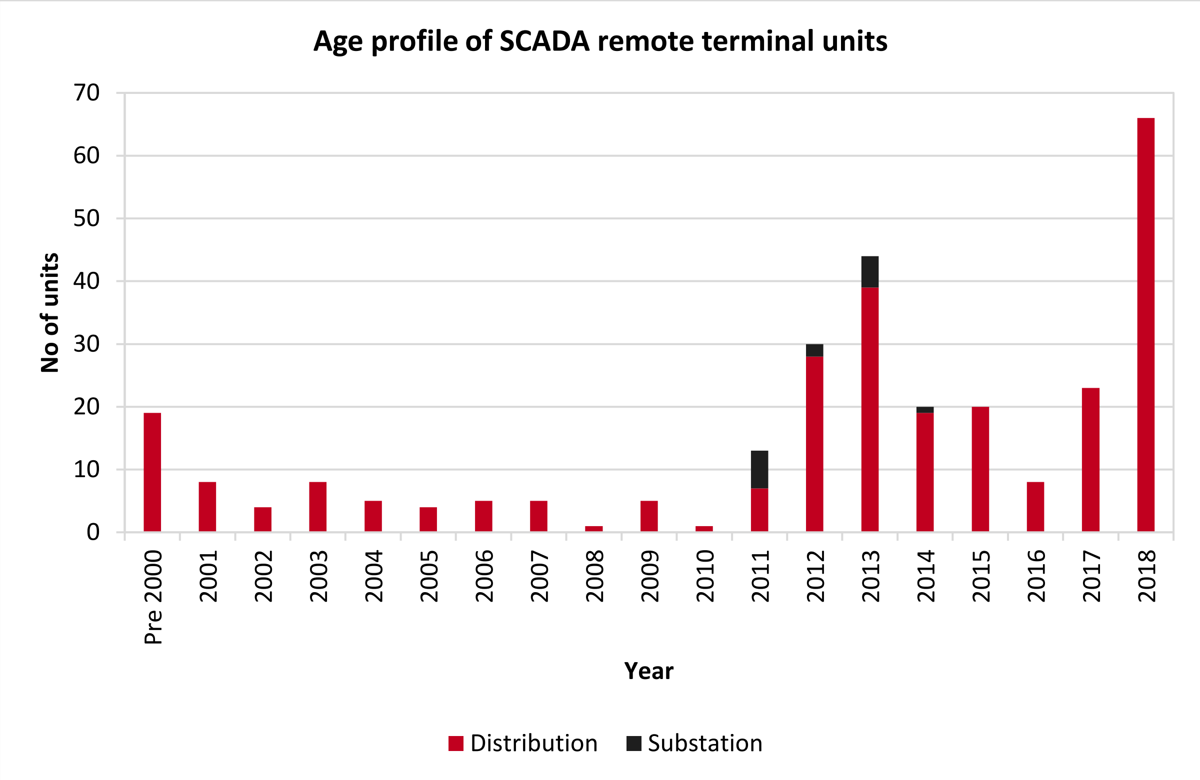


Figure 5-22 Age profile of SCADA Remote Terminal Units

Renewal programme

We will replace the protection communication link between Opaheke and Bombay from radio to fibre for an estimated cost of $60,000, and between Bombay, Pukekohe and Tuakau for an estimated cost of $96,000 in early 2019 due to reliability issues associated with aged and obsolete (unsupported) technology.

We have expenditure on the system each year to implement improved functionality. We have a maintenance services agreement with the vendor of the SCADA system for support, with an annual fee.

Based on the age profiles of SCADA RTUs, we expect to replace around 70 units during the planning period as older electronic RTUs tend to become unreliable after 25 years and are generally replaced as part of overhead switchgear replacement programme.

5.9.5 Load control equipment

Load control equipment consists of ripple injection plant located at substations, and load control relays located at each of our consumers premises connected to some form of interruptible load. For residential consumers, the interruptible load is generally hot water heating.

When we need to manage the load on our system, we send a signal from our SCADA master station to the relevant ripple injection plant(s) which in turn send a signal to the assigned load control relays.

We have five Ripple Injection plants installed on the network at Bombay, Glenbrook, Opaheke, Pukekohe and Tuakau with an average age of 20 years.

Age profile

Figure 5-23 shows the age profile of our Ripple Injection Plant.

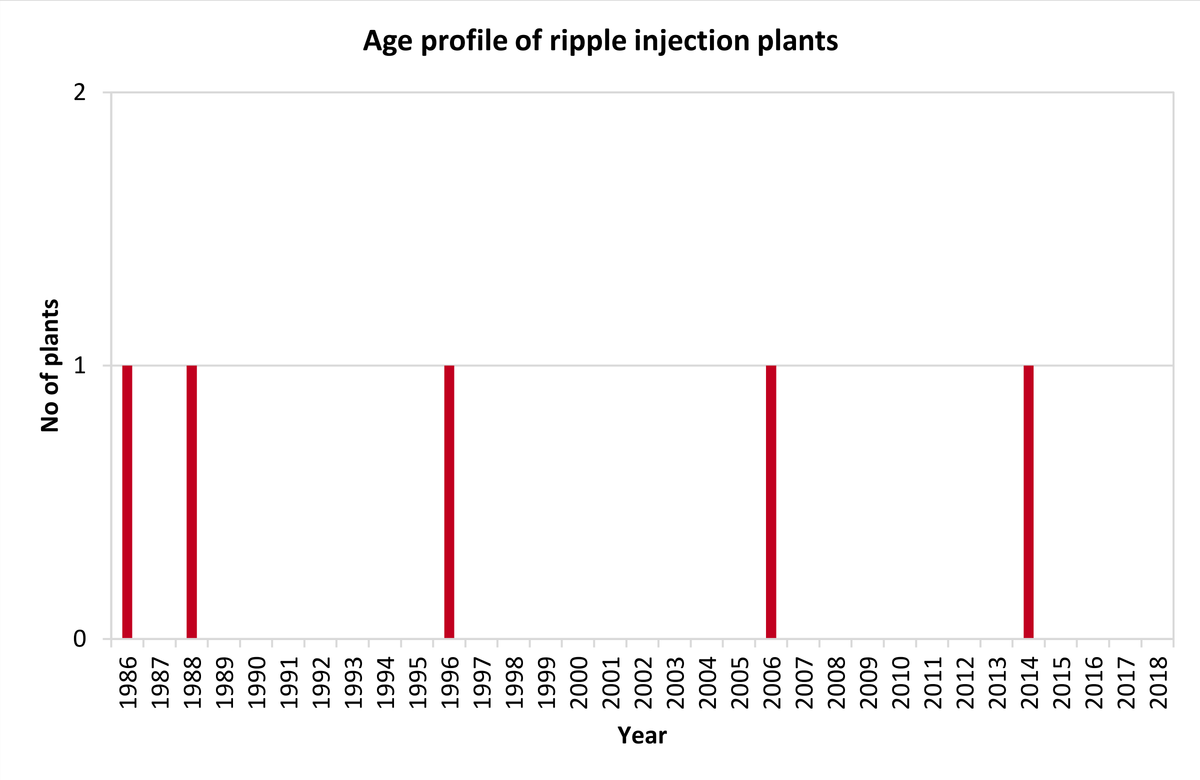


Figure 5-23 Age profile of Ripple Injection Plant

We have over 3,460 load control relays installed on our network associated with legacy meter installations. We have reduced the number of individual load control relays by introducing Smart Meters on our network which have the ripple receiver inbuilt.

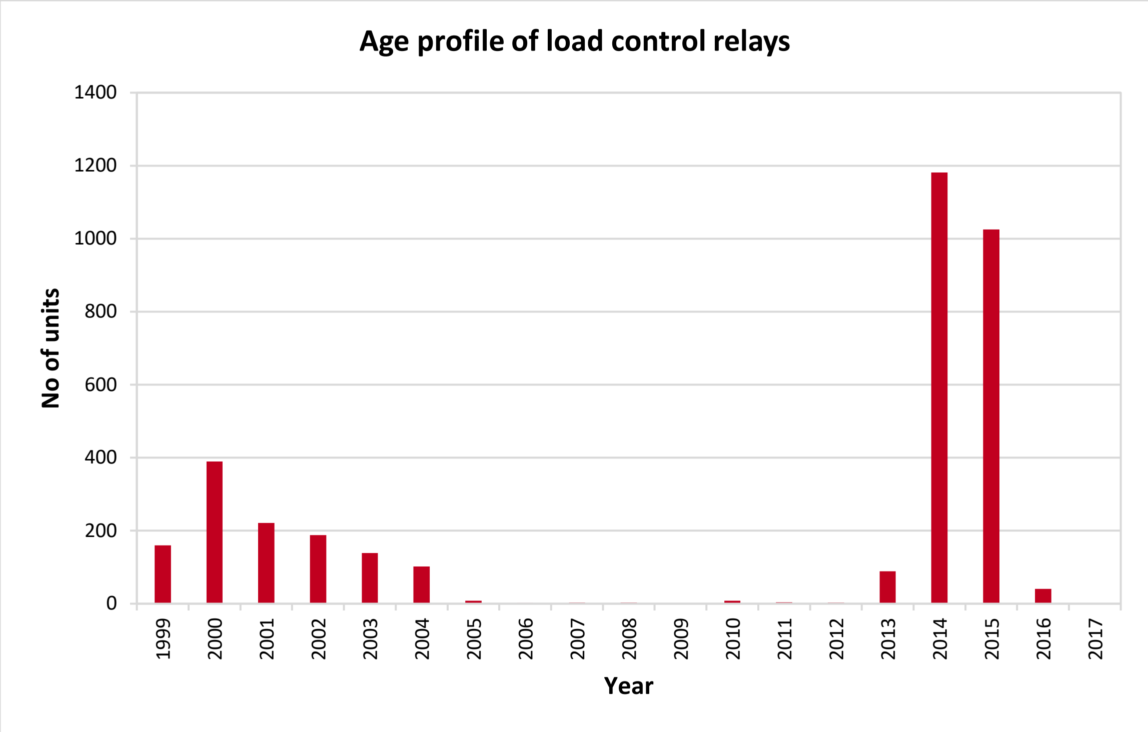


Figure 5-24 Age profile of Load Control Relays

Inspection and maintenance practices

Our inspection and maintenance cycles for our ripple injection plants are:

Activity	Type	Frequency
Ripple Plant – Visual Inspection	Inspection	6 Monthly
Ripple Plant – Test and Service	Routine Maintenance	Annual

Table 5-32 Inspection and maintenance cycles for our ripple injection plants

Renewal programme

Ripple plant at Opaheke and Tuakau is relatively new and no renewal expenditure is forecast in the planning period. Replacement of the ripple plant converter at Pukekohe to address age and reliability issues has been completed in early 2018.

New ripple plant will be installed with the proposed new Zone Substations at Pokeno, Drury South, and Bombay area, superseding the 33kV plant at Bombay which is in below average condition.

The load control coupling equipment at Glenbrook GXP has deteriorated and is planned to be replaced in 2019/20 at an estimated cost of $300,000. The injection signal plant at Opaheke Substation will reach the end of its life in 2026/27 when it is planned to be replaced at a cost of $200,000.

As we upgrade legacy meter installations to smart meters, we will remove the standalone ripple receivers, so no future expenditure is expected on these.

5.9.6 Auxiliary battery banks

110V and 24 VDC battery banks are installed in our network to supply power to protection schemes, control and metering and equipment components (such as circuit breaker operating coils) that need DC supplies to operate.

We have 27 battery banks installed in our network with installation dates ranging from 2009 to 2018. We have 9 units of 110V battery banks and 18 units of 24V battery banks. The average age of our battery banks is 3 years.

Age profile

Figure 5-25 shows the age profile of our auxiliary battery banks.

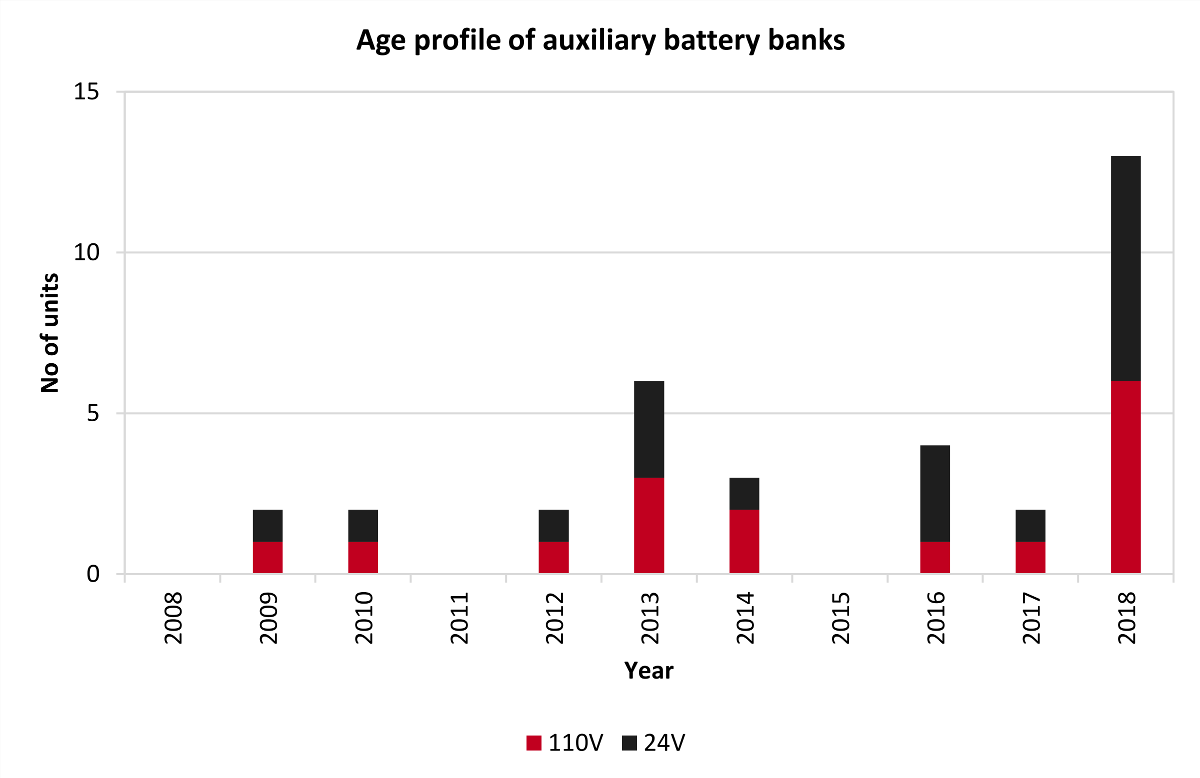


Figure 5-25 Age profile of Auxiliary Battery Banks

Inspection and maintenance practices

We carry out periodic visual inspections and tests ensure that the auxiliary battery cell voltages remain within acceptable ranges and the battery chargers operate as required depending on site criticality.

Activity	Type	Frequency
Battery Inspection and Test - GXP	Routine Test	3 Monthly
Battery Inspection and Test – Zone Sub	Routine Test	3 Monthly
Battery Inspection and Test – Radio Site	Routine Test	12 Monthly

Table 5-33 Inspection cycle for Auxiliary Battery Banks

Renewal programme

As auxiliary battery banks have an expected life of 8 years (80% of their design life of 10 years), conservative financial planning assumes we will replace our entire auxiliary battery bank fleet at least once during this planning period, although actual replacements, particularly as technology improves, may be favourable to this assumption. The trade-off between the relatively low replacement cost and high impact of failure will be considered when planning the renewal programme. Battery banks close to their end of life at the start of the planning period will be replaced twice during this period. We also replace batteries in remote field devices, however these are undertaken as part of their routine maintenance and are not included in this forecast.

5.9.7 Summary of other system fixed asset expenditure forecast

Expenditure Forecast ($000)	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Capital Expenditure										
Voltage regulator replacement	360									
New AUFLS/Extended Reserves Relays		300								
Protection relays replacement and upgrade	320					240				
Advanced Distribution Management System (ADMS)		1,500								
RTU Replacement	20	30	20	20	40	30	30	30	10	20
Battery banks	20	30	30	20	30	60	30	20	30	30
Load Control Plant Replacement	300							200		
Network Locks Replacement	420									
Other protection, control and radio communications renewal	50	50	50	50	50	50	50	50	50	50
Capital Expenditure Total	1,490	1,910	100	90	120	380	110	300	90	100
Operational Expenditure										
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	120	110	110	130	120	120	110	120	140	110
Load control equipment	40	40	40	40	40	40	40	40	40	40
Battery banks	20	20	30	20	20	20	20	20	20	20
SCADA and Communications	40	40	40	40	40	40	40	40	40	40
Operational Expenditure Total	240	230	240	250	240	240	230	240	260	230

Table 5-34 Other system fixed asset expenditure forecast summary

5.10 Renewal and maintenance of other assets

5.10.1 Backup Generators

We have 3 mobile generators, which although don't form part of our regulated asset base, are used to maintain supply during planned and unplanned outages, and 1 fixed generator at our head office to maintain supply to our SCADA and the control room. In addition, we have generator service provider agreements with two generator rental companies for use under works or emergency situations.

Age and size profile

The generators range in size and age from 6 years to 22 years, and from 15kVA to 250kVA.

Inspection and maintenance practices

These are maintained at 250 hours running time, and the fixed generator at our head office is checked every month and run every 6 months.

Renewal programme

We have no firm plans to replace these generators in the short term, however given the age profile, replacement during the planning period is almost certain.

Expenditure forecast

We have no capital expenditure forecast in the short term on generators, and operating costs are allocated to the projects which they are used on or corporate overheads for the building generator.

5.10.2 Emergency critical spares

Description and quantity

We hold a number of critical spares at our main depot in Pukekohe, such as distribution transformers, distribution switchgear, cables, overhead line conductors, poles and cross arms. Some of these are new, and others have been recovered from projects and are now held as spares. Additionally, we have two spare 33/11kV power transformers which can be returned to service should a serious fault develop with one on the network. We have repurposed the old Tuakau 33kV substation site to create an alternative storage site and are redeveloping space in our depot for storage of critical spares.

We do not hold any spare 110/22kV transformers as the units in service are relatively new and have N-1 redundancy.

Inspection and maintenance practices

During 2019, we will review our current processes and update our critical spares list and stock requirements. Additionally, we will implement a critical spares management process, which will look at periodic inspection, refurbishment and maintenance of spares held.

Expenditure forecast

We do not forecast any material expenditure on critical spares in the short term but will be compiling a plan to ensure sufficient stock levels in the medium term.

5.10.3 Network operational locks

We have historically used a single suite of locks for all operational purposes across the network. It has been established that there are potential safety issues and access risks such that an improvement in security is now planned. Locks on all ground mounted equipment are to be upgraded using a multi-tier system in 2019/20 at an estimated cost of $420,000.

5.10.4 Head office and depot

Description

We own the land and buildings used for our Head Office and Depot. We operate all of our activities from this one site, located in Pukekohe.

Our site is approximately 3.2 hectares in size, and we have offices, storage buildings and workshops covering just over 4,000 square meters.

Renewal programme

We have commenced a site redevelopment at our Glasgow Road Head Office and Depot, the first stage of redeveloping the operational yards and workshop space began in 2018 and the redevelopment of the main office building to accommodate increased staff numbers, and provide a more modern and usable working space, will continue into 2019 and 2020.

5.11 Assets owned by Counties Power at Transpower Grid Exit Points

In addition to the assets we own at our own substations, or as part of our distribution system, we also own assets located at Transpower's GXPs.

These assets are included in the asset category overviews above.

5.11.1 Bombay Substation

Within the substation building, the following equipment is installed:

- 24V DC battery bank;
- 2 sets of overcurrent and earth-fault line protection;
- 3 sets of Line differential protection;
- 3 sets of UHF inter-trip communication links;
- 1 set of metering equipment (33kV only); and
- 1 SCADA RTU and associated equipment.

A 33kV load control plant and an aerial mast are installed within the grounds of the substation, as well as a Disaster Recovery container which has a backup SCADA control terminal.

5.11.2 Glenbrook Substation

Within the substation building, the following equipment is installed:

- 4 sets of Line differential protection;
- 1 set of metering equipment;
- 1 SCADA RTU; and
- 2 fibre optic cables to the Glenbrook Load Control Plant.

The 33kV Glenbrook Load Control Plant is located near the Transpower Glenbrook Substation on land owned by Counties Power.

5.12 Summary of capital and operating expenditure

Replacement and renewal capital expenditure

Asset Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Subtransmission network	**50**	**50**	**50**	**50**	**50**	**3,500**	**500**	**50**	**50**	**50**
Maioro Line Refurbishment						450	450			
Bombay - Ramarama Tower Line Renewal						3,000				
Other Subtransmission Renewal	50	50	50	50	50	50	50	50	50	50
Zone Substations	**650**	**50**	**350**	**350**	**350**	**400**	**50**	**50**	**50**	**50**
Zone Substation switchgear										
Replace Maioro 11kV Switchboard						350				
Oil Separator Plant	600									
Power Transformer Refurbishment			300	300	300					
Other Zone Substation Renewal	50	50	50	50	50	50	50	50	50	50
Distribution and LV lines	**7,170**	**6,680**	**8,240**	**7,910**	**9,350**	**10,100**	**10,420**	**10,080**	**9,350**	**10,380**
Distribution poles and crossarms										
Overhead Renewals	3,350	3,350	3,300	3,300	3,300	3,290	3,300	3,300	3,300	3,300
Distribution conductor										
Copper Replacement Programme	2,050	910	1,990	2,500	2,460	2,210	2,410	2,600	2,640	3,150
Swan Replacement Programme	900	1,380	2,200	1,390	2,950	3,750	4,050	3,530	2,630	3,230
HV Feeder section replacement	650	390	300	300	300	300	300	300	300	300
Urban LV Replacement	120	550	350	320	240	450	260	250	380	300
Overhead Safety Compliance	100	100	100	100	100	100	100	100	100	100
Distribution and LV cables	**330**	**340**	**350**	**360**	**510**	**520**	**530**	**540**	**550**	**560**
Distribution and LV cables Renewal	150	150	150	150	300	300	300	300	300	300
LV Pillar Renewal	180	190	200	210	210	220	230	240	250	260
Distribution substations and transformers	**750**	**650**	**660**	**750**	**660**	**400**	**450**	**450**	**450**	**450**
Distribution transformers										
Transformer Renewal Programme	750	650	660	750	660	400	450	450	450	450
Distribution switchgear	**2,320**	**1,740**	**1,400**	**1,380**	**1,570**	**960**	**960**	**960**	**960**	**960**
RMU replacement	1,720	1,140	920	960	1,120	480	480	480	480	480
Overhead switchgear replacement	600	600	480	420	450	480	480	480	480	480
Other System Fixed Assets	**1,490**	**1,910**	**100**	**90**	**120**	**380**	**110**	**300**	**90**	**100**
Capacitors and Voltage regulators										
Voltage regulator replacement	360									
Protection										
New AUFLS/Extended Reserves Relays		300								
Protection relays replacement and upgrade	320					240				
SCADA and Communications										
Advanced Distribution Management System (ADMS)		1,500								
RTU Replacement	20	30	20	20	40	30	30	30	10	20
Battery banks	20	30	30	20	30	60	30	20	30	30
Load Control Plant Replacement	300							200		
Network Locks Replacement	420									
Other protection, control and radio communications renewal	50	50	50	50	50	50	50	50	50	50
Subtotal	**12,760**	**11,420**	**11,150**	**10,890**	**12,610**	**16,260**	**13,020**	**12,430**	**11,500**	**12,550**
Capitalised Maintenance	900	900	900	900	900	900	900	900	900	900
Total	**13,660**	**12,320**	**12,050**	**11,790**	**13,510**	**17,160**	**13,920**	**13,330**	**12,400**	**13,450**

Network operating expenditure

Asset Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Subtransmission network	**140**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**
Subtransmission lines	140	110	110	110	110	110	110	110	110	110
Subtransmission cables	-	-	-	-	-	-	-	-	-	-
Zone Substations	**450**	**460**	**440**	**430**	**430**	**430**	**430**	**430**	**430**	**430**
Zone Substation transformers	150	160	120	120	120	120	120	120	120	120
Zone Substation switchgear	120	120	120	110	110	110	110	110	110	110
Zone Substation other equipment	90	90	110	110	110	110	110	110	110	110
Zone Substation buildings and grounds	90	90	90	90	90	90	90	90	90	90
Distribution and LV lines	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**
Distribution poles and crossarms	950	950	950	950	950	950	950	950	950	950
Distribution conductor	70	70	70	70	70	70	70	70	70	70
Fault indicators and Earthing	20	20	20	20	20	20	20	20	20	20
Distribution and LV cables	**290**	**290**	**290**	**290**	**290**	**290**	**290**	**290**	**290**	**290**
Distribution and LV cables	150	150	150	150	150	150	150	150	150	150
LV Pillars	140	140	140	140	140	140	140	140	140	140
Distribution substations and transformers	**270**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**
Distribution transformers	270	280	280	280	280	280	280	280	280	280
Distribution switchgear	**370**	**390**	**410**	**410**	**420**	**420**	**430**	**440**	**450**	**460**
Ring main units	120	130	150	150	160	160	170	180	190	200
Overhead switchgear	250	260	260	260	260	260	260	260	260	260
Other System Fixed Assets	**240**	**230**	**240**	**250**	**240**	**240**	**230**	**240**	**260**	**230**
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	120	110	110	130	120	120	110	120	140	110
Load control equipment	40	40	40	40	40	40	40	40	40	40
Battery banks	20	20	30	20	20	20	20	20	20	20
SCADA and Communications	40	40	40	40	40	40	40	40	40	40
Vegetation	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**
Vegetation	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
Public Safety Services	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**
Public Safety Services	150	150	150	150	150	150	150	150	150	150
Faults and Reactive Maintenance	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**
Faults	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Capitalisation	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**
less Capitalised Maintenance	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900
Total	**5,300**	**5,300**	**5,310**	**5,310**	**5,310**	**5,310**	**5,310**	**5,330**	**5,360**	**5,340**

6 Network Development

6.1 Planning approach

Our long-range plan focuses on developing our subtransmission network and zone substations by taking into consideration:

- Plans for new areas of supply (e.g. new subdivisions) and anticipated demand growth in existing areas of supply;
- Adequacy of distribution feeder network to meet future security and capacity requirements; and
- Adequacy of our points of supply, subtransmission network and zone substations to meet future security and capacity requirements.

Our short-range plan focuses on developing our distribution network, in particular feeder performance and capacity to meet our operational objectives. Factors we consider in our short-range plan include:

- Network safety;
- Customer connections;
- Overload relief;
- Voltage correction and control;
- Power factor correction;
- Service quality improvement;
- Operation and maintenance;
- Loss reduction; and
- Operating efficiency improvement.

We have adopted a longer planning timeframe and modified our planning approach to take into account the increasing time required to negotiate and agree on land-rights or new work for upgrades requiring land purchase, designations or easements.

6.1.1 Planning drivers and assumptions

The key drivers and assumptions for our investment plans include:

- The network is to meet all safety requirements;
- Selected options should maintain flexibility for future development if they can be economically justifiable;
- We will invest (where economically feasible) to meet our security standards (see section 6.1.3);
- We will invest to meet the demand forecast (see section 6.2); and

- We will make investment choices that minimise the risk of asset stranding.

6.1.2 Security criteria

Our security criteria have been established based on the level of service sought by the customers connected to our network, but also reflect historical network requirements and geographical constraints. We commission an annual survey of our customers, and from this plus feedback received through other means, we have established that, in general, customers are satisfied with the level of service they receive (outage frequency, response to faults, and restoration). Where customers are less satisfied they are rarely willing to pay more than a token amount more for a higher level of service. We use the customer service levels outlined in Section 3 to inform our security criteria.

Security criteria are one part of the overall mix of factors that result in the level of reliability that customers receive. The other factors include adverse weather, third party events, asset condition and operations and maintenance.

The Counties Power network uses the EEA 'Guidelines for Security of Supply in New Zealand Electricity Networks' as the basis for its network planning and seeks, as a minimum, to meet its requirements. In 2016 an independent review of our previous security of supply guidelines was carried out comparing these with those of our peer group. This was followed by an independent review recommending we reduce the number of categories and simplify the table as follows. The actual security levels have either remained the same or have been slightly raised.

Table 6-1 sets out the security criteria we use to design our network.

Class of Supply	Group Peak Demand (GPD) MVA	Examples	First Outage	Second Outage
C1	0 - 0.5	Customer Connection Urban LV distributor/substation	Repair Time	Repair Time
C2	0 -1.5	HV Radial Feeder (or spur from main feeder)	Repair Time	Repair Time
C3	Up to 12	Rural Zone Substations Feeders (22kV and 11kV)	within 3hrs 50% GPD Repair Time 100% GPD	Repair Time
C4	12 to 40	Zone Substations (includes subtransmission Feeders) (33kV or 110kV)	Immediately 100% GPD less 12MVA Remaining 12MVA - 3 hrs	Repair Time
C5	Large Customers	Large Industrial Customers	By agreement in connection contract	

Table 6-1 Counties Power planning security criteria

Notes to table:

- **GPD** is the Group Peak Demand
- **Repair time** is defined as the total time from the start of the outage until customer(s) have power restored (i.e. the total outage time as seen by the customer).
- **Immediately** means either an uninterrupted supply or restoration in under one (1) minute.

The term “First Outage” means the loss of any single supply system component (which can include disconnection for maintenance, etc.). Similarly, “Second Outage” means the loss of a second supply system component.

To limit the impact of outages on customers, the maximum substation size will normally be based on a firm capacity of 40MVA (i.e. two 20/40MVA transformers and associated subtransmission circuits). Whilst outages of a substation are infrequent this limits the number of customers affected by an event to around 15,000. Past plans were based on higher capacity substations (i.e. two 30/60MVA or three 20/40MVA transformers), however studies have shown that the customer impact of this configuration is not desirable.

The impact of this together with the changes to the number of customers per feeder (below) will impact on forward planning, resulting in a larger number of smaller substations than previously considered, with the overall aim of improving (reducing) our SAIDI and SAIFI performance figures, i.e. providing better customer service in addition to improving resilience under HILP events. Limiting substation firm capacities to 40MVA has the added benefit of making it easier to restore load following HILP events, as this will result in more substations and therefore increased interconnectivity. We believe this is an appropriate response to the increasing number of storm events observed in recent times.

Criteria for customers

For larger individual customers, we set the security criteria for their supply based on the size of their load, their location, and any special conditions agreed in their supply contracts. Such customers may make a price-quality trade-off and pay a larger annual amount for higher levels of service compared with the average customers.

For most customers, who are fed by shared assets, it is not possible to set individual service levels and thus our approach is to aim to meet the targets developed above.

A further factor influencing network design is the adoption, in recent years, of monitoring network performance by reference to two factors:

SAIDI System Average Interruption Duration Index – this is the average time (minutes) of outages per annum experienced by a customer.

SAIFI System Average Interruption Frequency Index – this is the average number of outages per annum experienced by a customer.

The above factors include both planned outages and unplanned (fault) outages. Both factors have increased significantly in the last two years reflecting industry changes in working practices to accommodate the re-interpretation of some aspects of the Health and Safety legislation, however, our long-term aim is to reduce both values (See section 3.4 Service Reliability).

In the light of the above aim and the security of supply review we have revised our approach to the desirable number of customers fed on a HV feeder and will work towards the target value in table 6.2 in future. The value adopted is in line with typical customer numbers per feeder across other networks in NZ.

Feeder section	Max No Customers
6.1.2.1.1.1.1.1 Switch segment	300
Total feeder	1,500

Table 6-2 Customer numbers for feeders

We have identified that we currently have five feeders which exceed this number of customers and we are investigating ways of achieving the new target. In addition, the maximum number of customers between isolating switches on HV feeders is being targeted at 300 to assist with restoration when a fault occurs, where back-feeds from other feeders are available.

There are three basic approaches to responding to a feeder fault:

- Use automatic devices such as circuit breakers and reclosers;
- Control room operator response by using remotely controlled switches; and
- Sending a technician to operate equipment.

In each case the process followed is to isolate the fault and restore power to the remaining parts of the feeder. A critical aspect in restoration is doing so safely as inadvertently re-energising a fault (e.g. where lines are down following a car hitting a pole) could be fatal, so there are restrictions on what can be achieved by automatic and remote switching. Before relivening a line, it is usually necessary to carry out an inspection of the faulted section before enlivening, however we are installing indicators that show if a fault current has occurred which helps identify the location of the fault and thus allows for restoration of the rest of the line.

Criteria for feeders

Feeders are designed to meet the statutory voltage level requirements under normal operating conditions. Under emergency conditions these levels may be exceeded for short periods whilst switching or repairs take place.

In designing new or upgraded feeders we review the level of losses and seek to minimise these where economically viable.

A developing problem as new building takes place is that of Rural feeders supplying pockets of urban customers as land use changes and former small settlements are developed into towns or industrial centres. Rural feeders are typically overhead construction and have a lower reliability than urban feeders due to their exposure to external factors such as trees, birds, and strong wind.

Urban feeders also often have substantial sections of underground cable which normally provides a more reliable service than overhead lines. As urban boundaries of the network extend, some rural feeder sections can be reconfigured to connect the high density residential load to urban feeder sections to improve reliability. These feeder reconfigurations will generally utilise existing switches to change network open points but may require conductor upgrade in some cases.

6.1.3 Design standards

Our distribution network is predominantly rural with earlier subtransmission built at 33kV and distribution built at 11kV. At these voltages we can experience voltage constraints and high network losses typical of a rural distribution network. To mitigate these issues, where economically justified, we have been progressively migrating to two new voltage levels:

- 110kV as our standard subtransmission voltage; and
- 22kV as our standard distribution voltage.

Moving to a higher subtransmission and distribution voltage should also enable us to reduce the number of our zone substations that we need on our network as we can supply the demand from fewer sites, which should lead to lower costs overall.

However, an independent review of the significant impact of an outage of a very large zone substation on both SAIDI and SAIFI performance has resulted in us looking to limit the total load (and thus the number of customers) on our existing larger zone substations below the theoretical maximum and to similarly limit the capacity of new substations. This matches the approach adopted to the maximum number of customers on a feeder.

The capacity of these existing larger zone substations will be utilised as part of the resilience of the network by being able to support load through the network if a major event affects another adjacent substation.

The move to 110kV/22kV has progressed steadily for our eastern area (i.e. the area fed from the Bombay GXP) and it is intended that the remaining pockets of 33kV/11kV will be removed with the project to establish a new Bombay Area substation to allow the decommissioning of the old substations at Mangatawhiri and Ramarama.

The western area of our network is supplied at 33kV from the Glenbrook GXP with two circuits each to Karaka and Waiuku Substations and a single spur line from Waiuku to Maioro substation.

The establishment of Special Housing Areas (SHAs) at Glenbrook Beach and Clarks Beach together with subdivisions at Kingseat and Waiau Pa has resulted in a study to establish the appropriate development plan for the subtransmission system in this area. The Glenbrook GXP does not have 110kV supplies available and there would be a major expense by Transpower to provide this. Alternatively, we could build 110kV lines from the Bombay GXP across to the western area, however again there would be significant costs as well as the issue of obtaining suitable routes and this would further concentrate load on this GXP.

We have therefore looked at the long term projections for land development in the western area including the notified SHAs, plus land zoned for future housing in the Unitary Plan. This has established that a 33kV subtransmission system in this area is appropriate for the foreseeable future. Similarly retaining 11kV as the feeder voltage is appropriate for normal purposes, noting that for very long rural feeders, conversion of them (or parts of them) using autotransformers, may be appropriate in future to address voltage drop issues.

Sub-transmission and zone substation design

The District Plans in our network area presently allow for overhead lines of up to 110kV and 100MVA capacity lines as a permitted activity in rural and formerly non-residential areas.

To meet the security of supply levels in Table 6.1 the sub-transmission circuits (either at 110kV or 33kV) are arranged such that there are at least two circuits into class C4 substations. These circuits may be either on a ring arrangement or parallel circuits from the Grid Exit Point.

There will be two transformers at such C4 class substations capable of meeting the requirement that in the event of a fault 100% of the peak load, less 12MVA, can be supplied continuously with the balance being restored within 3 hrs. The preferred transformer size is 40MVA.

Transformer impedances are chosen to limit the maximum fault current (at 22kV) to 16kA. The power transformer tap changer range at our zone substations defines the minimum voltage levels for our subtransmission network.

New substations (and existing one as they are re-built) follow good engineering practice adopting non-oil circuit breakers, bus section switches, unit protection, increased arc containment and multiple fire zones.

To provide flexibility for future load developments, the switchboards are rated to be supplied with 60MVA transformers and provision is made to extend the switchboard to connect additional distribution feeders. Most of the existing outdoor substations have space for a third transformer, future substations will be designed for two transformers and capacity will be expanded by alternate engineering solutions. Smaller substations (Class C3) may be fed on a spur line, however where possible a ring feeder approach will be adopted to allow for future growth and provide greater security. A single transformer may be installed, however provision for a back-up (on site or transported in) will be made to cater for a transformer failure.

Distribution network design

We generally run our feeders radially out from the zone substations. Our preferred feeder configuration, where geography allows, is for a Y construction with the bottom of the Y starting near the zone substation and the ends of the two arms of the Y being open parallels with other feeders, normally from another zone substation. In this configuration we divide our feeders into three by installing reclosers (in rural areas) at the Y junction of the feeder and remotely operable switches at each end arm of the top of the Y. In the urban network, the feeder architecture can differ due to the greater number of switching points, however through the use of ring main units placed in strategic locations, switching of feeders allows for quick isolation and response to faults.

Where possible we will locate main feeder routes off high traffic routes or underground where significant traffic hazards exist. We generally avoid double circuit overhead lines along high traffic routes if possible, as issues have been found with this arrangement.

We also use a mix of trunk and distribution feeders on our distribution network to limit the loading on each distribution feeder:

- Our trunk feeders provide N-1 redundancy to small switching stations which in turn typically supply four smaller distribution feeders; and
- Distribution feeders are designed to have sufficient capacity to be able to pick up half the load of an adjacent feeder if it trips.

Table 6-3 specifies our standard distribution network conductor and cable ratings.

Feeder Type	Cable	Rating	Design Rating	Overhead Conductor	Cross-section	Rating	Design Rating	Notes
Distribution	$630mm^2$ Al	590A	590A	Cockroach	$256mm^2$	560A	560A	1,2,3,4
	$240mm^2$ Al	360A	240A	Cricket	$160mm^2$	420A	280A	3
	$95mm^2$ Al	200A	140A	Grasshopper	$85mm^2$	290A		3, 5
				Fluorine	$40mm^2$	190A		5, 6

Notes to table:
1. Include fibre optic cables in our underground cables for protection, SCADA and cable temperature functions;
2. Use underground cables in urban areas;
3. Use AAC conductor where possible. AAAC may be used as an alternative for long spans;
4. Use maximum span lengths of 80-100 meters;
5. Run spurs for volt drop considerations rather than capacity.

Table 6-3: Cable and conductor ratings

The design criteria we utilise for our distribution switchgear (RMUs) is that they shall have:

- A fault rating of 16kA;
- A bus rating of 630A;
- 3 phase switching; and
- Remotely operable disconnectors on four function units.

Equipment ratings

We design and operate our network to the following acceptable equipment load limits:

- 100% of OFAF zone substation power transformer ratings, with short duration overload to 120% under fault conditions;
- 100% of the switchgear, line and cable ratings;
- The acceptable load limit on distribution transformers depends on the period of maximum demand and whether it is a winter or summer peak load:
    - 100% of the transformer rating where the maximum transformer load is spread over many hours; or

  - 150% of the transformer rating where the load is peaky over one to two hours, such as supplying a residential subdivision.

We are investigating the use of cyclic ratings of circuits as loading on them increases, as this may provide an appropriate way of delaying further investment – particularly where such loading only occurs for short durations such as during plant outages (planned or unplanned).

6.1.4 Network development options

Network development philosophy

Our network design philosophy consists of the following elements:

- We make sure any development option we consider has public and employee safety as a primary requirement;
- Where appropriate, we shall implement phased solutions to defer major subtransmission and distribution investment;
- Our network is primarily radial with the ability to inter link various feeders if the need arises;
- We continually reassess and re-configure our network configuration to respond to load increases and changes in demand patterns to optimise overall performance;
- Upgrade of our distribution feeder network allows better utilisation of tie-lines and alternative feeds. This has also allowed us to defer upgrading some zone substations by temporary re-allocating load to adjacent zone substations;
- Where we identify potential increase in demand (see Section 6.2), we plan for significant line routes and substation sites to serve the demand and seek designations well in advance;
- The security criteria recognises that it is not economic to provide full redundancy on all our network; and
- We continue to improve our network performance by employing effective design and construction techniques, such as triangular line construction and strategic deployment of pole-mounted circuit breakers and fault passage indicators.

Subtransmission development

When identifying subtransmission development options, we consider:

- Long term load and usage forecasts in the area, considering consumer type and needs;
- How the subtransmission system will support new zone substation transformer capacity within growth areas;
- Alternative solutions using existing assets or taking advantage of technological innovations;
- Optimising capital investment on the network;
- Stranding risk; and
- The impact of existing and proposed embedded generation developments.

Distribution Development

When identifying distribution network development options, we consider:

- Industrial, commercial and residential developments affecting specific areas of supply and requiring capacity augmentation;
- The need for feeder reinforcement or distribution tie line construction for security reasons;
- Voltage regulation, particularly on rural feeders, and the need or otherwise for regulators, reactive compensation or voltage conversion;
- Loss reduction through correct conductor selection and optimised switching configurations; and
- The impact of existing and proposed embedded generation developments.

Development on the network boundaries

We share common boundaries with two electricity networks, Vector to the north, WEL Networks to the south, and although not immediately on our border, Powerco's 'Eastern' network is adjacent to the south-east of our network.

When considering development options, including capacity and security projects we will look to share investment with our neighbours as the most economic solution may be one that satisfies a number of mutual needs.

We share interconnection points at 11kV with Vector in two locations, and in one location with WEL Networks.

Conversion to 22kV

Conversion to 22kV operation can be used to increase our network capacity to meet load growth and service requirements effectively. This involves upgrading the 11kV distribution network to 22kV where there are identified capacity and voltage constraints, and each area for conversion is assessed on its individual merits, including consideration of a range of alternatives. For all new work, we install insulators, cables, switchgear, and transformers (>50kVA) to be capable of 22kV operation. Where practical we will convert the relevant distribution network to 22kV when 11kV capacity or voltage constraints occur and there are no cost effective solutions to improving 11kV capability (e.g. the use of voltage regulators, reconductoring or network reconfiguration).

Low Voltage reticulation

New subdivision developments drive the extent of underground low voltage reticulation augmentation. We liaise closely with local surveyors and property developers who are responsible for the majority of subdivision works in the area to identify their needs. Planning of network augmentation also takes into account the growth plans developed by local councils. The majority of overhead low voltage augmentation work comes from smaller rural subdivision developments.

In the longer term, we expect alternative technologies to change the way in which our LV network is used, ranging from periods where electric car charging systems significantly increase LV demands, through to periods where high levels of distributed generation output could lead to reverse power flows and voltage rise. To assist with network performance under either scenario, we have moved to shorter runs of low voltage feeder, and to use uniform cable sizes for the length of the feeder.

New equipment types

We regularly investigate new equipment types to determine if they are cost effective in enhancing our network performance. We follow the process identified in Section 4 to ensure that any new equipment meets construction, technical and safety standards. Our teams identify potential new equipment as part of carrying out compliance and safety surveys, asset renewal policies for aging assets and new customer requirements.

6.1.5 Network alternative solutions and new technology

Through our planning processes, we identify possible network alternatives in our solution list. Technology in this space continues to improve and reduce in cost, however to date, the largest network alternative solution we have in place is demand management using our ripple load control system.

Our load management system is integrated with our SCADA system and permits us to switch controllable load during peak periods to maintain our system half-hourly targets, which minimises transmission peak demand, as well as ensures our network equipment operates within its ratings. We also monitor output from large Distributed Generators through our SCADA system, which also assists in managing peak demand.

Embedded generation, energy storage, energy efficiency measures, demand side management initiatives and new load types such as Electric Vehicles (EVs) may result in modified load growth patterns. We are presently monitoring the uptake of all of these technologies, with a specific interest in EVs due to their expected level of penetration and potential for overloading the local LV network if ownership is clustered and charging is not controlled.

We continue to keep a watching brief on demand side management technologies and options, along with other new supply side technology and where appropriate undertake or participate in trials to understand how these options could impact on our business. We describe later in this section our trial of battery storage on the network.

In the medium term, improved metering technology will enable us to offer tariffs that better reflect delivery cost structures and an increased range of customer options and responses around demand management and energy consumption, as well as providing significant service and operational benefits to customers, network companies and retailers.

Load control

We currently use ripple load control for network demand optimisation and transmission peak demand management for transmission pricing purposes. We generally limit load control to 5 hours per day on any customer load and only during regional coincident peak demand (RCPD) periods during Upper North Island (UNI) peaks. Our network peak occurs just after the UNI peaks on a typical day.

While the precise maximum load control capacity is measurable, in reality the total amount of load that can be shifted at any one time is based on the prevailing conditions on the network. The effect of load control can vary in different areas and throughout the seasons, but typically over the winter, where Counties Power's maximum demand occurs, controllable load is between 5% and 10% of the total demand. We have approximately 32,000 controlled ICPs on the network, which provide an after diversity maximum demand controllable load of 9MW via Bombay GXP and another 2.2MW via Glenbrook GXP.

The technology deployed to control load is likely to change over time with the advances in consumer technology. Electric vehicles may pose a challenge in the future with the additional loading coming onto the network at times that may differ from traditional peak loading. Our advanced metering system offers functionality for load control separate to ripple load control, and applications for this will be considered as appropriate.

Distributed generation

Several of our consumers own distributed generation systems that connect to our 11kV or 22kV distribution network.

Generally, the network can support connection of generation in a specific location of:

- Up to 4MW of generation to our 11kV distribution network;
- Between 4 MW and 12 MW of generation to our 22kV distribution network; and
- Above 12 MW of generation to our subtransmission network.

We have recently connected a small number of photo-voltaic and wind systems, of ratings less than 10kW, to our low voltage network. We record the location of these, but do not have control of these installations.

When assessing an application to connect distributed generation to the network, we consider the following effects on the network:

- Reactive power flows – to maintain correct power factor;
- Voltage control range – to ensure compliant voltage is maintained in all load circumstances; and
- Harmonics – to ensure the plant does not create excessive harmonic levels and power quality problems.

Our Distributed Generation Guideline sets out the network connection and technical requirements and is consistent with the Electricity Industry Participation Code, Part 6 – Connection of Distributed Generation. This Guideline can be downloaded from our website at www.countiespower.com.

Impact of large scale generation on the network

The establishment of a generator can impact the network in various ways, depending on the capacity and the security of the generation. It is not usual for generation of the size connected to a distribution network to have any level of security (i.e. an N-1 capacity) as in most cases there is a single generator. In these cases, the network must be designed and installed to cater for load flows under the zero generation case. Thus, the impact will not reduce capital or operational costs, but can impact revenue. Specific negotiation is therefore required with proposed generators to reflect their needs and impact.

If the generation plant does have a true firm capacity then this may reduce the network requirements and thus costs. This can be fully reflected if the network is to be built to connect the plant, however in some cases it could lead to stranded assets reducing the benefits.

As noted above there are technical restrictions on the size of generator that can be connected at different voltage levels and locations and these must be established for each case. Significant sized generation may need connecting back to the nearest zone substation (or higher voltage lines) and in remote rural generators may be restricted to 0.5MW for connection to 11kV lines.

For the purposes of load forecasting no specific provisions have been made for potential larger scale generation being established on the network.

Impact of small scale generation on the network

To date the uptake of PV generation at a small scale in NZ has been low by comparison with many other countries, however these have had various subsidy provisions by their governments. There is considerable pressure on the NZ Government to introduce subsidies and such a move could see a significant increase in their adoption. At household levels other generation options include wind turbines, micro-hydro systems, biomass and biogas engines and diesel or bio-diesel generators. The establishment costs of these systems are currently high, and they are not normally attractive to customers.

The impact of small scale generation at present is low and localised. With the normal domestic load profiles (morning and evening peak demands) PV installations do not reduce the peak demand from a property and thus the network must be designed to meet these peak loads. The impact is thus an economic one with the reduction of income from energy sales.

The impact of household small scale generation is dependent on the provision of local storage (batteries) covered below.

For the purposes of load forecasting no separate provisions have been made for small scale generation being established on the network, however the growth rates used for each location will reflect any impact from existing installations.

Batteries - network scale

Counties Power established a Battery Energy Storage System (BESS) at Tuakau zone substation in 2017 with an output capacity of 250kW and stored energy capacity of 500kWh. This has the capacity to fully power around 100 houses for two hours. This is further discussed in Section 6.4.6.

Such batteries offer the ability to reduce the peak demand on a substation and thus defer network upgrades. In this they are comparable to the provision of a diesel generator, however the generator provides a non-time limited level of capacity (subject to fuel storage).

For the immediate future the cost of network connected batteries does not appear to be an economic option, however they are considered on an individual project basis at network planning stage along with diesel powered generation peak lopping options.

Batteries - domestic scale

The installation of a storage battery at a domestic property, coupled with on-site PV (or other non-continuous generation) would result in a reduction in peak demand for the property. An appropriately sized system could see the property being disconnected from the network, however customers generally wish to retain a connection for when their system does not operate for any reason.

Whilst it has been surmised that battery prices would drop as production increases it is of note that the market leader (Tesla Powerwall 2) increased their prices last year. With the indicative current NZ installed costs of $12k - $17k at the time of writing, economic justification for their usage is questionable and the uptake is very low.

In the longer term one proposal is to use batteries removed from EVs due to reduced range as home storage systems. At present EV battery replacement has been on an exchange basis, however this may change. This could reduce the costs of establishing a home storage facility, however the price will need to reduce significantly for it to be economically attractive to most homes.

Impact of storage batteries on the network

For the purposes of load forecasting no separate provisions have been made for the impact of storage batteries on the network. Network connected systems are considered at project stage and should a housing development be proposed with PV/batteries the impact will be considered in the demand assessment and subsequently the network provided.

Electric Vehicles (EVs)

The adoption of EVs in New Zealand has been slower than in many other developed countries. Whilst this will reflect the substantial government provided subsidies overseas, the distances and usage patterns in New Zealand are also a factor.

During 2018, New Zealand surpassed 10,000 registered EVs. The New Zealand Government has set a goal of 64,000 EV registrations by 2021.

There is considerable pressure for the government to offer some form of subsidy for purchasers of electric cars which could see a significant increase in sales.

EV options for larger vehicles such as buses and trucks are currently at the early trial stage, however the range available and the weight of multiple batteries (which reduced payload) means that the economics are usually less attractive than cars.

Impact of EVs on the network

The primary concern from a network viewpoint for EVs is the requirement to charge them. Typical home chargers for overnight re-charging draw of the order of 7kW. The standard household service connection is a 60A single phase supply which will supply a continuous load in the order of 15kW, thus there is available capacity for such chargers at the property.

However, the network in the street is installed taking into account a factor called “diversity” which is simply a reflection that not every house in a street will try to take the full capacity of their connection at the same time. The network is designed and installed based on a loading figure called the After Diversity Maximum Demand (ADMD) which is typically around 2.6kW per house in the Counties Power region (see Section 6.2.2). This results in the network cables and transformers being loaded on average in the 60% to 70% range. Installing a network to meet every house drawing 15kW, rather than 2.6kW, would be proportionally more expensive and would lead to very low utilisation.

Whilst the arrival of an EV at a single property is very unlikely to be an issue on the network the arrival of several in a street with owners arriving home and plugging in at the same time could lead to local overloading and the need to install additional distribution transformers and Low Voltage cables. This is considered highly probable as the customers likely to purchase new EVs are most probably in a high socio-economic area and an effect called “clustering” is likely to occur with one initial purchase triggering neighbours to follow. A similar phenomenon was observed when spa pools were first introduced to New Zealand. This occurred with many houses in more exclusive areas installing them – each with a 6kW load – which lead to overloaded network cables, transformers, with low voltage to customers and, in some cases, fuses blowing resulting in outages.

The ability to control the impact of chargers (either through load control or through pricing structures) is very desirable if additional costs are to be avoided from reinforcement of the network so that it can meet a relatively short-term loading situation. Such mechanisms would encourage EVs to be charged at off peak times, allowing for connection to the network without the need for significant network investment.

Over time, major uptake of EVs would also see the need to reinforce the High Voltage distribution feeder cables and zone substations, however this would be identified by the annual review of load increase at this level of the network.

There are also available very fast EV chargers rated at 22kW, however these cannot be simply “plugged in” at household level and their impact can be addressed on an individual basis. recent reports on battery technology identify a focus on reducing charging time which would require even larger chargers, however these would be installed in public locations and specific supplies would be provided to them. Similarly, the impact of electric buses and trucks is most likely to be concentrated at specific charging points (e.g. depots) and local reinforcement can be arranged with the customer prior to the load occurring.

Other future energy options

Hydrogen

An alternative approach to the reduction of emissions is to replace fossil fuels (petrol/diesel/gas) with hydrogen which when burnt produces only water. The key issues have been around producing hydrogen and then its distribution. Overseas some vehicle fleets have been successfully converted to run on hydrogen, but only from a local supply point.

For the production of Hydrogen, the traditional method has been to use electrolysis to split water into hydrogen and oxygen, but this requires electricity. More recent developments have seen the production of hydrogen using artificial or alternatively supported natural biochemical processes which do not require an external power supply, but use energy from the Sun.

The localised production of Hydrogen at a household level, coupled with fuel cells to produce electricity to supply the home could ultimately impact on the utilisation of (or even the need for) the electricity network, however this appears very unlikely within the planning period.

No allowance has therefore been made for such technology at this stage, however developments need to be monitored in case the technology develops rapidly.

6.1.6 Smart network programme

We have completed the construction of a meshed communication network (using Silver Spring Networks technology) and installed over 46,000 advanced meters on our network. This has allowed us to achieve a high level of smart meter coverage (over 90% the total number of ICPs) and provides a platform for developing a 'smart network'.

Although we are still developing tools and processes based on this network, having a smart network will help us improve the reliability of the power supply, make it easier for people who have solar power and other energy alternatives to feed them back into the grid and help manage the electricity network in ways that are more efficient. Major network benefits of a smarter network include:

- **Faster fault location and repair.** The meter can send us a signal if it is suddenly out of power – a 'last gasp'. This reports the fault and helps the fault repair team work out exactly where the fault is, so they can get to it and fix it faster;
- **Better information during outages.** The smart network will talk automatically to our Outage Website and Application so that within minutes of a customer's power going on or off the status will be updated. It also means the fault team will be able to give earlier assessment of likely repair time;
- **Better system data means better engineering choices.** The data from the smart network will help our engineers do more accurate modelling and make more informed choices about when each part of the network will reach capacity and need to be upgraded;

- **Early identification of network issues.** The data from the smart meter can be used to identify voltage issues, quality of supply, and potential defects such as broken neutrals through the use of advanced analytics tools;
- **Improved measurement of energy use.** The data allows us to improve reconciliation and has led to lower 'unaccounted for' energy on the network; and
- **Future proofing for new technologies.** When coupled with other smart network technologies lays the foundation for future proofing our network for two-way power flows and other impacts arising from distributed generation and storage technologies connected to our network.

From a consumer perspective, the half hourly power data that can be provided by smart meters allows more informed choices about power use. Retailers can offer tools, like online usage data, to help consumers manage their power use, and in conjunction with smart pricing plans, it is possible for the power industry to offer incentives to those who can save power at peak times.

To date, expenditure on establishing the smart network and undertaking the meter rollout is over $15 million. Over the short term, expenditure on meters which can utilise the smart network capability will continue.

6.2 Demand forecast

The maximum demand on our system is the main driver for investing in our network. Our demand forecast defines future network requirements and is a key input into determining the appropriate timing for capacity and security related investment in our subtransmission and distribution networks for the AMP period.

Demand forecasts estimate the amount of electrical load required in different parts of the geographical area served by the network. Forecasting future demand is subjective and uncertain; and only provides an indication of when potential capacity and security issues are likely to occur on our network.

We have traditionally been a small, predominantly rural, distribution network, with demand particularly sensitive to changes in industrial demand within our area. However, this is already starting to change, and planned developments and local authority zoning should see our domestic customer numbers more than double in the next 20 years. The majority of this growth is in urban areas although some is in urban pockets in more rural locations. Major industrial/commercial load growth is also already occurring. Particularly at Pokeno, but the Drury South industrial development is also underway.

Thus, we are facing a period of ongoing load growth with the associated need to invest in new zone substations and associated subtransmission circuits to supply the new developments. This will see the network develop into a predominantly urban one based on the location of ICP's although it will still have an extensive rural network of lines.

Counties Power recognises the potential changes in demand characteristics from increased energy efficiency in new homes, new energy usage patterns through the use of energy storage systems and increases in electric vehicle charging over time as the technology matures. Our demand forecast assumptions and approach are based on historical demand data and are reviewed each year as we see new trends emerge for energy consumption on the network.

We accommodate the sensitivity in our demand forecast by monitoring demand trends continuously, revising our forecast periodically and varying the timing of our planned work. If demand growth is slower than forecast, we may defer investment and conversely if the demand growth is faster than forecast, we may bring forward investment.

Figure 6-1 and Table 6-3 show our winter maximum system demand forecast to 2032.

Note that this forecast is a single "most likely" projection for illustrative purposes, when considering the options for individual areas we prepare additional load forecasts to reflect both a higher growth rate (e.g. to reflect new housing being developed faster) and also a lower growth rate to reflect a possible slowing of the regional economy.

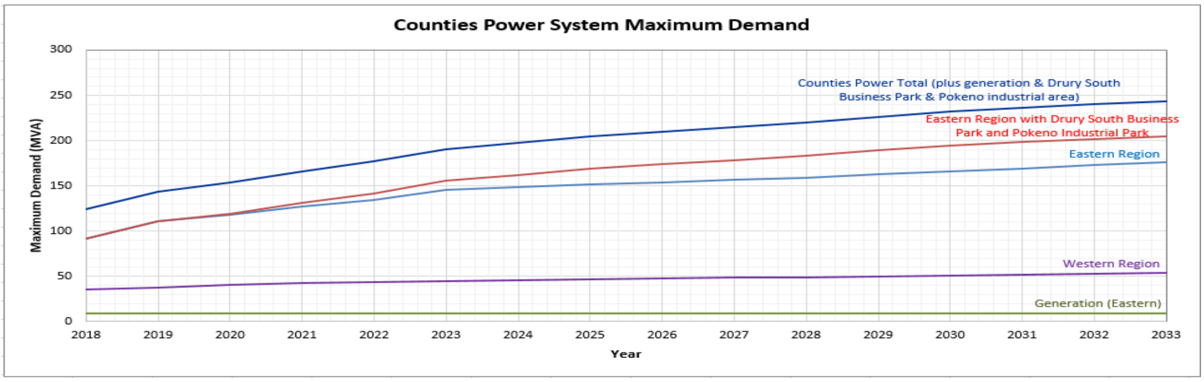


Figure 6-1 Winter Maximum System Demand

Description	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Eastern Area	91.3	110.4	118.4	126.7	134.5	145.1	148.1	151.2	153.9	156.5	159.1	162.5	165.9	169.3	172.7	176.1	6.2%
- with Drury South Business Park and Pokeno industrial area	91.3	110.4	119.1	130.8	141.9	155.9	162.3	168.7	173.7	178.6	183.4	189.1	194.7	198.1	201.5	204.9	8.3%
Western Area	35.7	37.5	40.3	42.3	43.6	44.6	45.5	46.4	47.3	48.3	49.2	50.1	51.0	52.0	52.9	53.8	3.4%
Generation (Eastern)	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	0.0%
Counties Power Total (plus generation)	123.9	143.0	152.7	162.2	170.4	181.0	184.6	188.2	191.5	194.7	197.9	201.9	205.8	209.7	213.7	217.6	5.0%
Counties Power Total (plus generation & Drury South Business Park & Pokeno industrial area)	123.9	143.0	153.4	165.9	177.2	190.8	197.5	204.2	209.5	214.8	220.1	226.0	232.0	236.0	239.9	243.8	6.5%

Table 6-3 Winter Maximum System Demand[21]

Our analysis of the load duration curves, for the period November 2015 to October 2018, indicates that the peak demand on our network exceeds:

- 90% of peak demand 0.2% of the time; and
- 80% of peak demand 3.0% of the time.

[21] We have included any known development that could result in significant increase in demand in our area when developing our network development plan, although we have treated the Drury South business park and Pokeno industrial area developments separately given their potential magnitude and sensitivity to assumptions regarding reticulation timeframes and the nature of the load.

6.2.1 Demand forecast methodology

We develop our forecasts internally using a spreadsheet based model to forecast the future demand on our network for the planning period.

We start by developing forecasts for individual feeders based on 10-year historical trends and the anticipated growth of various sectors the feeder supplies. We then roll the individual feeder forecasts up to zone substation and ultimately back to the two Transpower GXPs supplying our network, Bombay and Glenbrook.

We use the following inputs to develop our demand forecast:

- **Substation demand data:** We use fifteen minute average demand data collected from our SCADA system to monitor loads on all incomers and feeders on our network. We use this data to analyse trends, load shifts and power factor for each feeder;
- **Embedded generation:** Every month we collect half-hourly data for generators over 200kW and analyse the data using applications we have developed internally for this purpose;
- **Coincident demands:** We extract the coincident maximum demand from the half-hourly data for our zone substations and embedded generation into our load forecasting spreadsheet.
- **System changes:** We record system changes and network reconfigurations to monitor load transfer between feeders and in various areas. We review these changes and consider spikes in active and reactive demands to verify the maximum demand for each feeder or zone substation;
- **Key customer demand:** We review the half-hourly energy data for key customers using demand meters installed at the various premises. We then examine demand trends to see if there is any change in growth at these sites. We also consult with our major customers to identify any planed future expansion and changes in their load demand;
- **Subdivision activity:** We track subdivision activities by feeder for the planning period based on our knowledge of local authority and developer's plans. Where load requirements are unavailable, we assume after-diversity maximum demands of 2.6 kW per lot for new domestic subdivisions and 10 kW per unit for small commercial subdivisions;
- **Land zoning:** To set long term loading expectations we consider the relevant Council zoning plans to identify the ultimate developments likely for an area and their impact on our network; and
- **General demographic and economic trends:** We collect demographic trend information from publicly available census data and on new connections to our substations[22]. We use this data to verify our demand forecast.

[22] Obtained from our daily operations

6.2.2 Load forecasting assumptions

Within the load forecasting model assumptions are made in regard to:

- Demand management;
- Distributed generation;
- Load developments; and
- Other drivers.

Each of these are described below.

Impact of demand management

Ripple control forms an integral part of our load management strategy and provides a vital network investment deferral option. We assume that peak demand on the network has the most efficient level of load control in place, and thus peak demand observed is exclusive of controllable load.

We incorporate power factor penalty charges in major supply agreements, which encourage our consumers to maintain an efficient power factor. We monitor the impact of this scheme and adjust our future load forecasts accordingly once we determine that a major consumer has lowered their demand through power factor correction.

Impact of distribution generation

We consider how likely a generator will be available when required when deciding if it is to be included in our demand forecast. Factors we consider are:

- **Generation availability**: is it run continuously or is it only run for limited periods at a time; and
- **Generation redundancy:** does the generation connection to our network have an appropriate level of redundancy. For example, if the generation is on radial feeders we do not include it to reduce zone substation maximum demand forecasts (as it is on "n" security). However, we can aggregate a number of such generators into our regional and system maximum demand forecasts as they are spread over a number of feeders and zone substations and not subject to a single common mode failure.

Given the nature of the large scale distributed generation currently on the network, we do not rely upon generation capacity for network support. However, we assume that peak periods include a level of distributed generation operating based on historic operating profiles. With the exception of Hampton Downs and Papakura (Electra) generation, no single generator would have a material impact on network demand at peak times.

Impact of uncertain load developments

Large scale residential subdivisions do not pose the same problems as industrial subdivisions as we can assume their contribution to demand with a reasonable degree of certainty.

For residential subdivisions, we work with the developer to understand the timeframes for subdivision stages to progress and assume that new housing developments will be evenly spread over a number of years. We normally assume uptake over a period of 18 months following reticulation of the subdivision, however for SHAs a faster uptake is also considered.

Industrial subdivisions provide a high level of uncertainty as often at development time the eventual occupier of the sites is not known, nor is their load size and type. We provide a standard three phase supply point unless more specific requirements are known. Often, we install dedicated transformers for large consumers as development progresses.

Other assumptions

We have used the following assumptions in developing our demand forecast:

- We have assumed a 2.6kVA ADMD for each dwelling[23];
- Power factor – As we know the power factor for most feeders from demand data, our load forecasting is in MVA; and
- Energy efficient appliances and industrial plant using power electronic devices will cause distortion of supply resulting in poor power factor and higher harmonics. This also applies to energy efficient lighting including both Compact Fluorescent bulbs and LEDs (this could ultimately lead to increased feeder loading). So far, the impact of such devices has been limited to localised issues and thus only their overall impact on slowing load growth has been factored into our demand forecasts.

Together our security criteria, design standards and our view on demand growth combine to form the basis for the investment programme over period covered by this plan. Whilst the assumptions above are used in this plan, as reinforcement projects are required, more detailed localised load forecasts are prepared considering a spread of development possibilities which feed into the detailed business case prepared before investment.

6.3 Development programme

The following sections provide an overview of current development programmes in our network. The development programme is split into the two network regions, the eastern region where the majority of the growth occurs, and the western region which is dominated by rural and industrial consumers. More information on the development programmes for each region is provided below.

6.4 Eastern region development plan

The Eastern Region is supplied from Transpower's Bombay Grid Exit Point and covers areas supplied by our Opaheke, Pukekohe, Tuakau, Mangatawhiri and Ramarama Zone Substations.

Our subtransmission network in the Eastern region consists of:

- A 110kV ring from Bombay to Pukekohe and Tuakau;

[23] 2.6kVA ADMD per dwelling is based on historical demand data and is subject to review particularly with changing energy usage in new homes. The current figure has recently been verified by checking smart meter data in subdivision developments undertaken in the last few years.

- Two 110kV lines from Bombay to Opaheke;
- Two 33kV lines from Bombay to Ramarama; and
- One 33kV line to Mangatawhiri.

Figure 6-2 and Figure 6-3 below show the single line schematic for the subtransmission network supplied from the Bombay grid exit point.

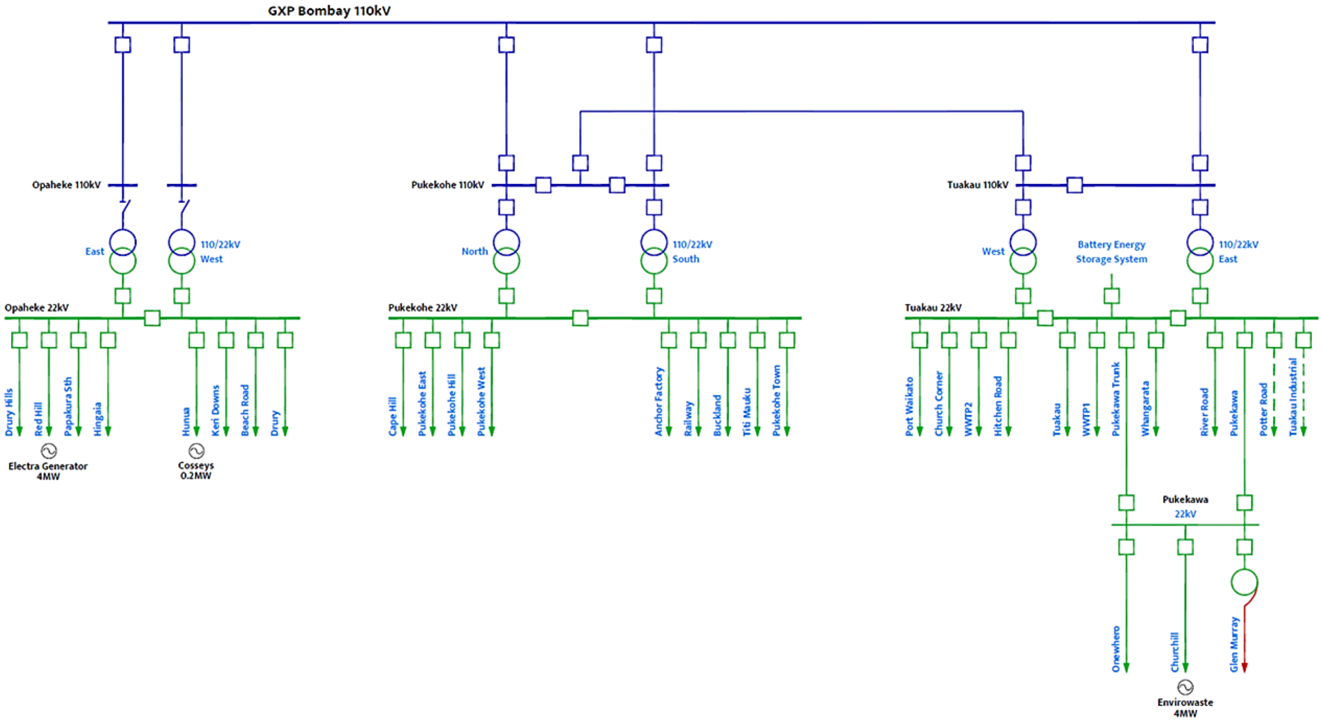


Figure 6-2 Single Line Schematic of the Eastern Region 110kV subtransmission network

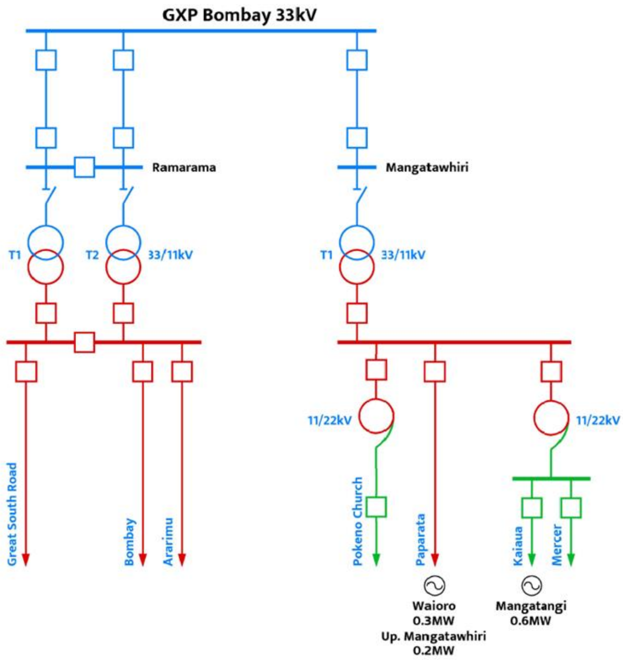


Figure 6-3 Single Line Schematic of the Eastern Region 33kV subtransmission network

Figure 6-4 and Table 6-4 show the demand forecast for the Eastern Region and the Eastern Region zone substations.

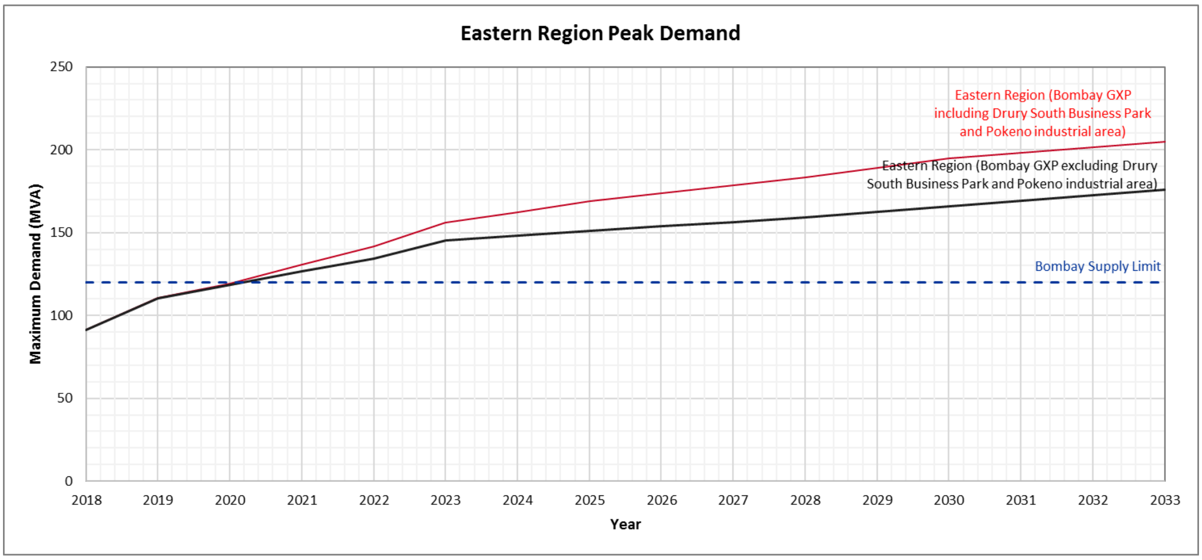


Figure 6-4 Winter Maximum Demand Eastern Region

Zone Substation		Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Pukekohe	110/22kV	37.2	39.8	42.9	44.2	45.5	46.7	48.0	49.3	50.6	51.9	53.1	54.4	55.7	57.0	58.2	59.5	4.0%
Opaheke	110/22kV																	
- without Drury South Business Park		24.7	29.1	30.6	33.9	36.0	37.4	38.8	40.1	41.1	42.1	43.0	44.7	46.4	48.1	49.8	51.5	7.2%
- with Drury South Business Park		24.7	29.1	30.6	36.2	40.6	44.2	47.9	51.6	54.9	58.1	61.3	65.3	69.3	71.0	72.7	74.4	13.4%
Tuakau	110/22kV	16.5	26.1	16.3	16.7	16.9	17.1	17.4	17.6	17.8	18.0	18.3	18.5	18.7	19.0	19.2	19.5	1.2%
Pokeno	110/22kV	0.0	0.0	17.1	21.2	26.2	35.7	37.2	38.6	40.1	41.6	43.0	43.1	43.1	43.1	43.2	43.2	11.7%
Ramarama	33/11kV	6.7	7.0	7.5	7.6	7.7	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1%
Mangatawhiri	33/11kV	6.8	8.3	8.4	8.5	8.6	8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9%
Bombay Area	110/22kV	0.0	0.0	0.0	0.0	0.0	14.7	14.9	15.1	15.2	15.4	15.6	15.7	15.9	16.1	16.2	16.4	0.7%
Eastern Region (Bombay GXP including Drury South Business Park and Pokeno industrial area)		91.3	110.4	119.1	130.8	141.9	155.9	162.3	168.7	173.7	178.6	183.4	189.1	194.7	198.1	201.5	204.9	8.3%
Eastern Region (Bombay GXP excluding Drury South Business Park and Pokeno industrial area)		91.3	110.4	118.4	126.7	134.5	145.1	148.1	151.2	153.9	156.5	159.1	162.5	165.9	169.3	172.7	176.1	6.2%

Table 6-4 Winter Maximum Demand Eastern Region

We can expect significant residential growth in the Auckland Council area over the next 10 years. The Future Urban Land Supply Strategy (FULSS) states that there are currently 15,000 dwellings proposed on live zoned or special housing areas both within the large future urban areas of the Hingaia Peninsular, Drury-Opaheke and Pukekohe-Paerata areas, with a further 4,000 dwellings proposed on development ready sites throughout the rural settlements of Clarks Beach, Glenbrook Beach, Karaka North, Kingseat and Patumahoe. The FULSS has also identified land that will be brought forward in these areas in the next 10 years which will have capacity for a further 14,000 dwellings.

Within the Waikato District Council area, Pokeno in particular continues to see significant residential and industrial expansion, with further rezoning of land from rural to residential likely if the Proposed Waikato District Plan is adopted. However, it is Tuakau that has the potential to become the largest town in the Waikato area as it has fewer infrastructure constraints when compared to Pokeno. The Proposed Waikato District Plan has identified significant areas of residential zoned land in and around Tuakau, which, together with infilling and the redevelopment of land, is predicted to satisfy the development pressure that comes from being on the boundary with Auckland.

The development of the Drury South Business Park is now in progress. The earthworks stage of construction commenced in late 2017. Discussions with developers and potential customers in the area indicate that load will require supply in mid-2021.

We will continue to review demand growth at the Drury South Business Park, and if it is higher than anticipated, we will bring forward building the 110kV Drury South Area Substation (see Section 6.4.2).

The following sections (Section 6.4.2 to Section 6.4.7) describe the subtransmission and distribution issues and plans for each of the zone substation areas within the Eastern region.

We currently have four proposed regional development programmes within the Eastern region:

- Drury South Business Park supply (refer to section 6.4.2): develop our network to supply the proposed Drury South Business Park by building a new 110kV Drury South Area Substation and feeders, and reconfiguring our network to supply the proposed new development and surrounding area;
- Pokeno industrial area development (refer to Section 6.4.3): develop our network, including building a new zone substation, to supply proposed new industrial load connections in the Pokeno area;

- Eastern Supply Project (refer to Section 6.4.7): further development in our network area currently supplied by the Mangatawhiri and Ramarama substations by:
    - Converting our subtransmission network in the area to 110kV;
    - Building a new 110kV Bombay Area Substation in the vicinity of the Bombay GXP to replace the Mangatawhiri and Ramarama substations; and
    - Converting our distribution network in the area to 22kV operation, where there are network constraints.
- Paerata Rise and Karaka North residential area development (refer to Section 6.4.5): develop our network to supply proposed new housing load connections in the Pukekohe North and Karaka North areas.

These developments are explained further in the sections below.

6.4.1 GXP and Eastern area investment requirements

Transpower's Bombay Substation has a transmission capacity limit[24] of:

- 170 MW for high north flow into the Bombay bus from the Waikato; and
- 120 MW for high south flow into the Bombay Bus from the Auckland Region.

The south power flow limit could be reached by 2021 and the north power flow limit by 2026 given current demand forecasts.

Distributed generation within our network, approximately 12 MW, could defer the issue by one to two years. However, at present, 7 MW of this generation is connected to our network by a single rural distribution line so may not be relied on to be available if required.

Completion of the eastern supply project will allow us to decommission our 33kV supply from Transpower's Bombay Substation around 2022, to coincide with their need to replace end of life 33kV equipment.

Options considered

Transpower has indicated that they intend to install interconnecting 220/110kV transformers at Bombay to reduce loading on the 110kV circuits into Bombay. The timing of this work is still to be confirmed.

As part of our network development planning, we also consider solutions which provide transmission benefits, including reducing loading or diversification of Grid Exit Points.

6.4.2 Supply to the Drury South Business Park

Earthworks for the Drury South Business Park are well underway following investment approval provided by Auckland Council in 2017. However, as the development is still in the planning stages, we do not know when and how much load will be added to the network from the business park, although

[24] There is no apparent seasonal pattern to the high north and south load flows

initial approaches have been made by potential customers. We expect the business park could, over 10 years, contribute up to 30MVA of load to our network given a typical mix of industrial use. A section of the Bombay-Opaheke East 110kV line is being relocated in March and April 2019 to enable earth works and development of the Drury South Business Park.

Considered options

To cater for the uncertainty in demand and timing in the Drury South Business Park we have assumed an initial load of 3MVA in 2020 with an annual increase of 3MVA per annum up to a maximum load of 30MVA in 2029.

With the present network configuration, we would supply this new business park from our Opaheke substation in the short term with upgrades of existing distribution feeders. These upgrades were completed in 2018. We have considered the following three network options to meet the total expected load increase from the Drury South Business Park in the medium to long term[25] as well as the anticipated additional load from the expansion south of the Auckland City Rural Urban Boundary. Installation of distribution feeders within the business park and interconnection to the existing distribution feeder network at an estimated cost of $2.5 million and rebuild of the Bombay to Opaheke 110kV line tower section at an estimated cost of $3.0 million are common to all options.

- Option 1: Opaheke substation upgrade. This would involve the upgrade of existing transformers and switchgear at Opaheke substation, and the construction of two new distribution feeders from Opaheke substation to reinforce supply to the Drury South Business Park and other anticipated load south of the Auckland City Rural Urban Boundary. The estimated cost of this option is $10.5 million; or
- Option 2: Drury South area substation establishment (Bombay GXP). This would involve establishment of a new substation with supply from Bombay GXP at 110kV and a new section of 110kV line from the rebuilt 110kV tower line section to the new substation. The estimated cost of this option $18.5 million; or
- Option 3: Drury South area substation establishment (proposed new Drury GXP). This would involve establishment of a new substation with supply from a new 220/110kV Grid Exit Point arising from redevelopment of the Drury 220kV switching station by Transpower. The new substation could also be used to reinforce supply to Opaheke substation, and potentially new developments in the north-eastern part of our network. By supplying this new substation, as well as potentially the Opaheke substation from the new GXP, this would also provide diversity benefits and reducing the high impact, low probability (HILP) risk of all supplies coming from Bombay GXP. This option is estimated to cost $22.5 million.

We have also considered the alternative non-network options.

- Use of localised energy storage or distributed generation to reduce peak demand under N-1 scenarios. However, this option is, at present, costly for the level of utilisation and required capacity to supply the additional load at Drury South Business Park development. Counties Power is trialling new technology options to understand the value they provide as well as

[25] Up to 30MVA of additional load from Drury South Business Park development and surrounding area

actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Proposed investment

Our proposed investment is to build a new 110/22kV Drury South Area Substation to supply this additional load at the Drury South Business Park and anticipated additional load south of the Auckland City Rural Urban boundary. This new substation would supply the business park area, reducing the reliance on Opaheke substation and existing distribution feeders, and providing supply diversity.

This option was chosen because:

- The expected load growth in the area justifies a substation ahead of feeder reinforcement from Opaheke;
- Load growth in industrial/commercial developments is often very uneven, and a substation enables us to respond to requests for supplies for significant loads in a short timeframe;
- The establishment of an additional GXP in the eastern region reduces Counties Power's reliance upon Bombay GXP. Following the establishment of Drury GXP, it will supply two substations and Bombay GXP will supply two existing substations (Pukekohe and Tuakau) and two upcoming substations (Pokeno as discussed in Section 6.4.3 and Bombay as discussed in Section 6.4.7). At present all five existing substations in the eastern region are supplied from Bombay GXP; and
- The diversion of the existing Bombay-Opaheke lines into the new zone substation will allow 160MVA of load to be transferred between Bombay GXP and Drury GXP if necessary, which would offer significant operational flexibility if a HILP event were to occur, thus improving network resilience.

Our network development plan allows for this proposed new 110kV Drury South Area Substation to be supplied from the proposed new Drury GXP. The proposed new Drury GXP is also required by Kiwirail, who will require a supply from Transpower to electrify rail services in the area. Kiwirail will take a separate supply as they operate on voltages which are not standard for Counties Power.

In the 2018 Asset Management Plan, the proposed timing for the Drury South area substation was 2023/24. This has now been brought forward to 2020/21. The reason for this is that based on discussions with developers and potential customers in the area, we expect load to require supply in mid-2021, and in industrial/commercial developments load growth is often very uneven and it is important that we can respond to requests for supply for significant loads in a short timeframe. The timing of the new substation will be reviewed periodically as new information becomes available from the developer and potential customers.

Note that the timing for Transpower to convert Drury to a 110kV GXP is currently unchanged. In the interim, the Drury South area substation can be supplied from our Bombay-Opaheke 110kV lines if they are diverted into the substation as these lines have sufficient capacity to supply Opaheke and Drury South substations with the required level of security. We are investigating the possibility of accelerating the establishment of a GXP at Transpower's Drury switching station.

Refer to Figure 6-16 for the proposed subtransmission single line diagram for the proposed new Drury South area substation and 110kV supply from the proposed new Drury GXP.

Our development plan for proposed 110kV Drury South Area Substation is to:

- Upgrade Quarry Road sections of the Great South Road feeder and convert to 22kV operation to supply the initial stage of Drury South Business Park development. This was completed in early 2018;
- Relocate a section of the Bombay-Opaheke East 110kV line within the Drury South Business Park development area. This will be completed in early 2019;
- Establish a new Drury South substation at a cost of $20.5 million in 2020/21, comprising of:
    - Purchase land for the substation development in a location suitable for whichever transmission supply option we choose to progress. A conditional agreement has been reached to purchase a specific parcel of land for this purpose, which is expected to be finalised in FY2018/19;
    - Build the new 110/22kV substation and install subtransmission circuits;
    - Install new 22kV distribution feeders from the substation to accommodate new industrial loads and to interconnect with existing distribution feeders;
    - Divert the Bombay-Opaheke East and West 110kV lines to supply the new 110/22kV substation;
- Connect the new Drury GXP to the Drury South area substation at 110kV in 2022/23, with an estimated cost of $2.0 million; and
- Rebuild the 110kV Bombay to Opaheke East line steel tower section in 2024/25 with an estimated cost of $3.0 million. Note that this is being funded as a renewal project (see Section 5.2.3). The establishment of Drury GXP removes the need for this from a security perspective, however there are strategic benefits to having subtransmission links remain between GXPs to mitigate HILP risks.

Note that the costs and projects above do not include Transpower costs. We expect that these will be operational pass-through costs and will not require a capital outlay by Counties Power.

The following table summarises the proposed Drury South Business Park development plan.

Description	Scope	Timing	Estimated Costs ($'000)
Drury South Area Substation establishment	Build a new Drury South Area Substation with two 110/22kV 40MVA transformers and 22kV switchboard	2020/21	20,500
110kV connection from the new Drury South GXP to Drury South area substation	Build a new 110kV line section from the new GXP to the Drury South area substation	2022/23	2,000

Table 6-5 Drury South Business Park development plan

6.4.3 Supply to Pokeno industrial area

Changes in the Pokeno Structure Plan have seen increases in residential and industrial load in the Pokeno area. To date the largest development has been the establishment of the Yashili New Zealand Dairy Company plant, however we are expecting step change loads to be established in the area in the short term. In the past year we have established a supply to a new manufacturing plant with an initial load of 3MVA and an ultimate load of 8MVA in the medium term. We have also signed agreements to supply other customers requiring supply for over 10MVA of demand before the end of 2021.

Considered options

The 2018 Asset Management Plan assumed an initial load of 3MVA in 2018 with an annual increase of 2MVA per annum up to 20MVA of additional load in 2029. However, since then the approaches received from customers as outlined above have indicated that previous assumptions underestimated the upcoming load growth in Pokeno. Therefore, we have had to reconsider our approach to Pokeno.

In the short term it was identified that to provide supply to upcoming load in Pokeno, staged upgrades of the Whangarata feeder and establishment of Potter Rd feeder would be required before mid-2019. These projects have all been initiated and can be completed in the required timeframes. However, a longer term solution would still be needed.

We have considered four network development options to supply the Pokeno industrial area in the medium to long term:

- Option 1: Using Potter Rd and Hitchen Rd feeders from the Tuakau substation to supply a new switching station in the Pokeno industrial area. This would involve establishing a new switching station in the Pokeno industrial area, diverting 22kV feeders Hitchen Rd and Potter Rd from Tuakau substation to supply the switching station and installing a third 110/22kV transformer at Tuakau substation. The estimated cost of this option is $18.5 million; or
- Option 2: New Pokeno area substation. This would involve establishing a substation in the Pokeno industrial area and constructing a short section of new 110kV line connecting into the Bombay to Tuakau 110kV line. The estimated cost of this option is $16.0 million; or
- Option 3: New Pokeno Industrial feeder and a third transformer at Tuakau substation. This would involve constructing a new 22kV feeder (Pokeno Industrial feeder) from Tuakau zone substation to Pokeno and installing a third 110/22kV transformer at Tuakau substation. The estimated cost of this option is $6 million. However, this is unlikely to be practical as space is not available for additional feeder routes from Tuakau substation to Pokeno area; or
- Option 4: Bombay area substation feeder. This would involve constructing a new 22kV feeder from the Bombay area substation (see Section 6.4.7) to Pokeno. The estimated cost of this option is $6 million. This is unlikely to be viable as Bombay area substation is not scheduled to be carried out until 2021/22, which is later than required.

We also considered the following non-network development options:

- Localised energy storage or distributed generation to reduce the peak demand under N-1 scenarios, however this option is presently quite costly for the level of utilisation and required capacity in the Pokeno industrial area. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Proposed investment

In the immediate term our proposed investment is to carry out staged upgrades of Whangarata feeder followed by construction of a new 22kV feeder (Potter Road feeder) from Tuakau substation. In the short to medium term our development plan for the Pokeno industrial area is to establish a new zone substation in Pokeno.

This option was chosen because:

- The load forecast (including contracted supply agreements) justifies the establishment of a substation in Pokeno to provide the required level of network security and capacity;
- A new substation is preferred to the existing arrangement of supply from Tuakau as feeders will be shorter (and therefore less likely to be exposed to faults) and industrial customers in Pokeno will not be impacted by faults on rural feeders; and
- Existing feeders from Tuakau into the Pokeno area can be used to provide resilience for HILP events.

The overall plan is as follows:

- Upgrade Whangarata feeder sections along Ridge Road, Huia Road and Great South Road sections to increase backfeed capacity. These will be completed in early 2019;
- Install a new feeder from Tuakau zone substation to the Pokeno Industrial area (Potter Road feeder) to increase supply capacity in 2019/20 at estimated cost of $1.56 million (subject to securing a viable route);
- Establish a new Pokeno area substation at a cost of $16.0 million, as land and some procurement occurred in FY19, the future investment is estimated at $12.7 million:
    - Purchase land for the substation development in a suitable location. Land was acquired in the Pokeno area in 2018/19 for the purpose of establishing the substation;
    - Establish a new 110/22kV substation in Pokeno;
    - Install new 22kV distribution feeders from the substation to interconnect with existing distribution feeders;
    - Divert the Bombay-Tuakau 110kV line to supply the new 110/22kV substation;
- Part of the existing Hitchen Rd feeder will need to be undergrounded as residential development continues. This is estimated to be required in 2021/22 with an estimated cost of $590,000.

The following table summarises the Pokeno industrial area development plan.

Description	Scope	Timing	Estimated Costs ($'000)
New Potter Road feeder	Build new feeder from substation to Pokeno Industrial area via Potter Road	2019/20	1,560
Pokeno Area Substation Establishment	Build a new Pokeno Area Substation with two 110/22kV 40MVA transformers and 22kV switchboard	2019/20	12,700
Hitchen Rd feeder upgrade (Hitchen Rd)	Upgrade 1.3km of Hitchen Rd feeder	2023/24	590

Table 6-6 Summary of Pokeno industrial area development plan

6.4.4 Opaheke Zone Substation (Papakura area)

We expect significant residential growth in the area through the planning period associated with continued residential development in Karaka, Drury, Papakura and business park development in the area, particularly Drury South.

The Opaheke 110/22kV Zone Substation is supplied by two 110kV circuits from Bombay GXP. Opaheke Zone Substation supplies 488 distribution substations in the urban areas of Beach Road, Keri Downs, south of Papakura and Red Hill and some rural areas in Hunua, Drury and Hingaia. The load is predominantly residential, except for the Keri Downs area which is 12% commercial and 72% industrial. Opaheke is classed as a zone substation (C4) and is fully compliant with our security criteria (Refer to Table 6-1). Major consumers in this area include Independent Liquor, Winstone Aggregates and van den Brink Poultry.

Figure 6-5 below shows the Rural-Urban Boundary (RUB) map for the Opaheke Zone Substation supply area (Papakura area), outlining the areas for future growth (green boundary line).

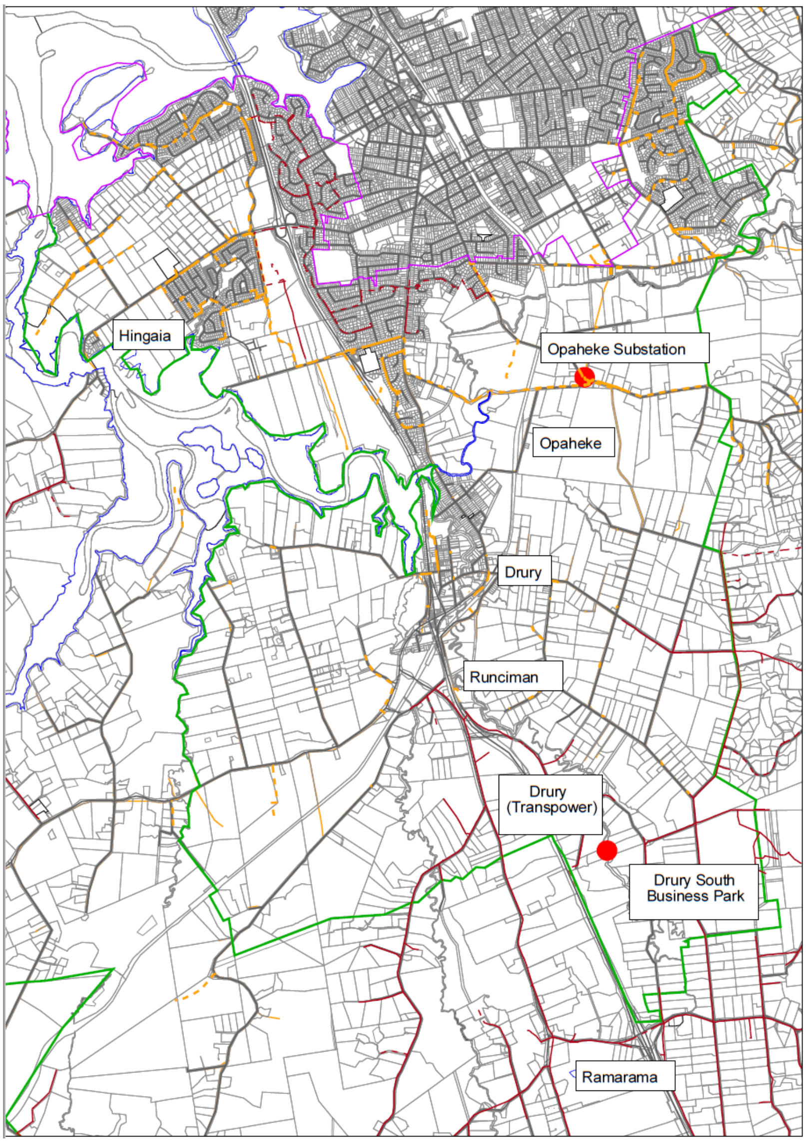


Figure 6-5 Opaheke Zone Substation Rural Urban Boundary (Papakura area)

The Opaheke load is largely residential and has a winter peak. The forecast peak demand for Opaheke Zone Substation and the distribution feeders from the substation is shown in Table 6-7.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Beach Road	5.9	6.5	7.1	8.0	8.8	9.6	10.4	11.3	12.1	12.9	13.2	13.5	13.8	14.1	14.4	14.7	9.9%
Drury	4.1	4.6	5.2	7.5	8.1	8.7	9.3	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	11.1%
Drury Hills	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.6	4.7	4.8	2.6%
Hingaia	2.9	5.2	5.4	5.9	6.5	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.8	8.8%
Hunua	4.8	4.9	5.0	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.2	2.0%
Keri Downs	3.7	5.5	5.5	5.6	5.7	5.8	5.8	5.9	6.0	6.0	6.5	7.0	7.5	7.9	8.4	8.9	9.4%
Papakura South	3.4	3.4	3.7	4.2	4.6	4.6	4.7	4.7	4.8	4.8	4.8	5.4	6.0	6.6	7.1	7.7	8.4%
Red Hill	4.2	4.6	4.6	4.7	4.7	4.8	4.8	4.8	4.9	4.9	4.9	5.5	6.1	6.7	7.2	7.8	5.6%
Zone Substation	**Max. Dmd (MVA)**	**Projected Maximum Demand (MVA): Winter Peak**															**Avg. Annual Increase %**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	
Opaheke	24.7	29.1	30.6	33.9	36.0	37.4	38.8	40.1	41.1	42.1	43.0	44.7	46.4	48.1	49.8	51.5	7.2%
Opaheke with Drury South Business Park	24.7	29.1	30.6	36.2	40.6	44.2	47.9	51.6	54.9	58.1	61.3	65.3	69.3	71.0	72.7	74.4	13.4%

Table 6-7 Winter Maximum Demand at Opaheke Zone Substation and Feeders

Opaheke Zone Substation Investment

The Opaheke Zone Substation demand forecast is shown in Figure 6-6.

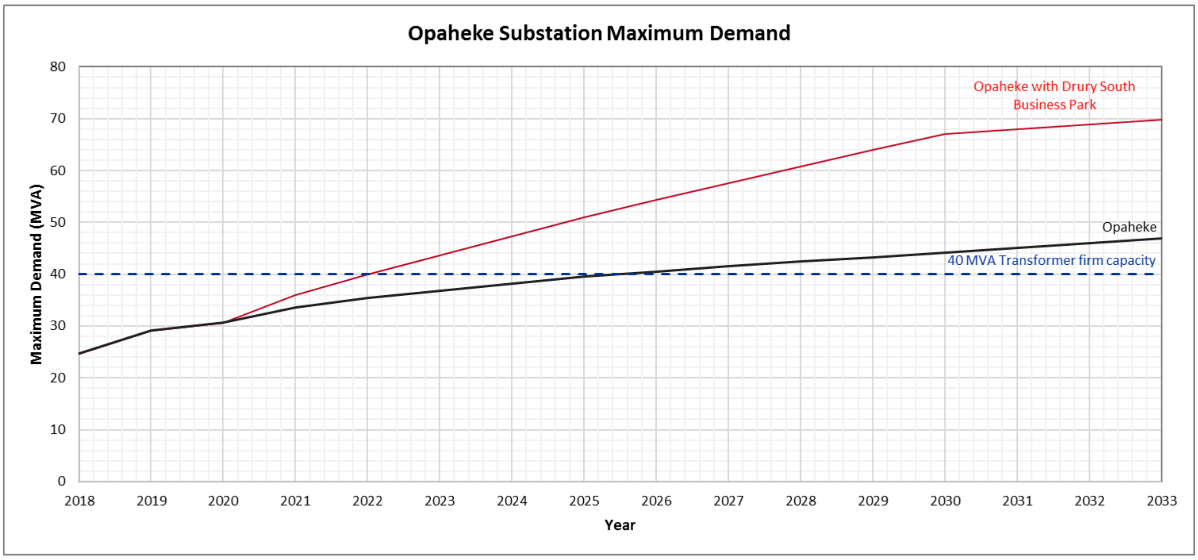


Figure 6-6 Opaheke Zone Substation Demand Forecast

Two 110/22kV, 20/40MVA transformers supply the load at Opaheke providing N-1 capacity of 40MVA. The Opaheke maximum winter demand is forecast to exceed the N-1 capacity of the transformers from 2026, or from 2022 if Opaheke supplies Drury South Business Park. As discussed in Section 6.4.2, we have made the decision to bring forward the establishment of the Drury South area substation to 2020/21 as we expect load to require supply in mid-2021. For industrial/commercial developments load growth is often very uneven and it is important that we can respond to requests for supply for significant loads in a short timeframe which would not be possible from Opaheke.

In the short term (before 2021), Opaheke will be used to supply the Drury South Business Park through existing distribution feeders.

In the medium to long term (2020/21 onwards), when the Drury South Business Park will be supplied by a new Drury South Area Substation then:

- The maximum winter demand is forecast to exceed 40MVA beyond 2026; and
- The loading on the two 110kV Bombay to Opaheke lines are forecast to remain within their N-1 capacity beyond 2033.

Our development plan for Opaheke Zone Substation is to:

- Following momentary voltage sags experienced by key customer as a result of faults on the rural feeders at Tuakau and Pukekawa substations we are installing earthing transformers at Tuakau substation for improvement of power quality. Similar units will be installed at Opaheke substation in 2019/20, at an estimated cost of $550,000 (see Section 6.4.6 for further details);
- Supply the early stages of the Drury South Business Park in the short to medium term before the establishment of a new Drury South Area Substation (see Section 6.4.2); and

- Investigate the use of cyclic ratings to defer the need for transformer reinforcement, at an estimated cost of $20,000. The previous AMP proposed replacing the 110/22kV transformers at Opaheke in 2024/25 when the load was forecast to exceed 40MVA. The new Counties Power planning guide suggests the use of short term cyclic ratings in excess of nominal rating to defer the need for investment. If this can be done at Opaheke, this will defer the need for transformer reinforcement at Opaheke beyond 2033. Investigations will be carried out in 2019/20 to confirm that the thermal chain supplying the Opaheke transformers can operate with short term cyclic ratings.

The Auckland Future Urban Land Supply Strategy 2017 (FULSS) states that of the total future urban land area in the south of Auckland comprising of Opaheke-Drury, Drury West, Hingaia and Drury South make up 23,400 lots. The load for these dwellings with associates services and commercial load could be up to 73MVA long term. This load will be shared between the existing Opaheke substation (27MVA peak), Drury South substation and the proposed Pukekohe North substation. Depending on how much industrial load is connected to Drury South substation, there may be the need for a fourth substation in the area. This possibility will be investigated and if this appears necessary land and line routes to this site will be acquired in time to ensure we are not restricted for options as the developments progress.

Opaheke Zone Substation Feeder Investment

The Opaheke area of supply includes the expanded Papakura Rural-Urban Boundary, and this area is characterised by being the area of supply nearest to central Auckland, its proximity to the motorway (SH1) and rail corridors (NIMT). Included in its area is the Hingaia peninsula just west of Papakura and Bremner Road just west of Drury, both of which have been designated as Special Housing Areas (SHA). The area of supply also currently includes that land that will be the future Drury South Business Park as detailed earlier in this section.

- The Hingaia Peninsula has already undergone significant subdivision of approximately 1,050 lots, and the potential for a total of 3,070 lots. In the load forecast we have assumed that these will all be developed over the next 15 years;
- The Bremner Road Subdivision has commenced construction of stage one of multi-stage development of around 1,200 lots, and the potential for further subdivision development of over 1,400 lots in the neighbouring Jesmond Road SHA area. These have been assumed to incur demand over the next 10 years and 10 to 15 years respectively. The total Drury West area has the potential of the order of 11,200 lots;
- The Opaheke-Drury development is constrained by waste water capacity and the waste water upgrade works are expected between 2028 and 2032, triggering the start of the development. The development has potential of the order of 8,200 lots;
- The Quarry Road SHA development, in the southern area of the Drury South Business Park, has around 1,000 lots. These have been assumed to incur demand over the next 5 years; and
- Other smaller subdivisions could be developed around the North Opaheke area. Typical sizes are between 50 and 300 lots. These have been allowed for in the demand forecast.

Figure 6-7 shows the demand forecast for Opaheke substation feeders.

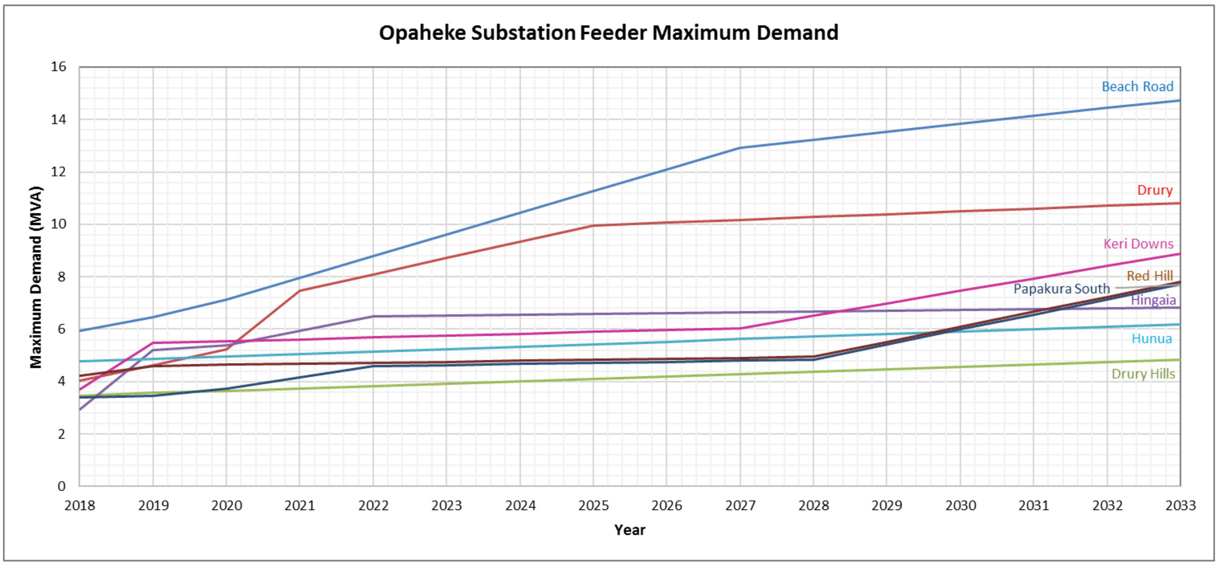


Figure 6-7 Feeder Demand Forecast at Opaheke Zone Substation

Our development plan for Opaheke Zone Substation Feeders is to:

- Upgrade Bremner Road, Jesmond Road and Norrie Road sections of the Drury feeder in 2019/20 with an estimated cost of $300,000 to increase backfeed capacity to Anchor Factory feeder;
- Upgrade Hingaia Road section of the Hingaia feeder in 2021/22 with an estimated cost of $400,000 to increase backfeed capacity to Anchor Factory feeder; and
- Conversion of the Papakura South feeder to 22kV operation in stages across 2019/20 and 2020/21. This is driven by the need to replace distribution switchgear on the feeder (see Section 5.7.3);
- Replace the 22kV switchboard at Opaheke Substation in 2022/23, with an estimated cost of $2 million to increase backfeed capacity to Beach Rd, Drury and Hingaia feeders. The primary driver for this is the need for more feeder bays but will also address a known condition issue associated with the switchboard (see Section 5.3.4);
- Create a new feeder to reduce customer numbers on Beach Rd feeder in 2023/24 at a cost of $1.25 million;
- Create a new feeder to reduce customer numbers on Hingaia feeder and improve network performance in 2023/24 at a cost of $500,000;
- Create a new feeder to reduce customer numbers on Red Hill feeder and improve network performance in 2023/24 at a cost of $1.8 million;
- Rebuild a section of Drury Hills feeder to improve network performance in 2023/24 at an estimated cost of $880,000; and
- Create a link between Beach Rd and Hingaia feeders to improve backfeed options in 2023/24 at a cost of $200,000.

We considered the use of localised energy storage or distributed generation to reduce the peak demand under N-1 scenarios, however this option is, at present, costly for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Summary of Opaheke Area Development Plan

Description	Scope	Timing	Estimated Costs ($'000)
Drury feeder upgrade (Bremner Road, Jesmond Road and Norrie Road)	Upgrade a total of 1km of Drury Feeder along Bremner Road, Jesmond Road and Norrie Road	2019/20	300
Opaheke power quality	Earthing transformer to address power quality issues at Opaheke	2019/20	550
Opaheke transformer rating review	Investigate the use of cyclic ratings to defer the need for transformer reinforcement	2019/20	20
Hingaia feeder upgrade (Hingaia Rd)	Upgrade a total of 1.7km of Hingaia feeder along Hingaia Road	2021/22	400
Replace 22kV switchboard at Opaheke substation	Replace 22kV switchboard at Opaheke to allow for new 22kV feeders to increase backfeed capacity to Drury, Hingaia and Beach Road feeders and reduce customer numbers on all three feeders	2022/23	2,000
Beach Rd feeder split	Create a new feeder to reduce customer numbers on Beach Rd feeder	2023/24	1,250
Hingaia feeder split	Create a new feeder to reduce customer numbers on Hingaia feeder	2023/24	500
Red Hill feeder split	Create a new feeder to reduce customer numbers on Red Hill feeder	2023/24	1,800
Drury Hills feeder rebuild	Rebuild part of Drury Hills feeder to improve network performance	2023/24	880
Beach Rd / Hingaia feeder link	Create a link between Beach Rd and Hingaia feeders to improve backfeed options	2023/24	200

Table 6-8 Summary of Opaheke Area Development Plan

6.4.5 Pukekohe Zone Substation

The 110/22kV Pukekohe Zone Substation is supplied by three 110kV circuits from Bombay GXP, of which two are directly connected to Bombay and the third is connected via Tuakau. Pukekohe supplies 657 distribution substations in the urban areas of Buckland, Cape Hill and Pukekohe and the rural residential loads towards the eastern parts of Pukekohe and Titi Mauku. The load is predominantly residential and commercial load with some industrial load in Buckland. Pukekohe is classed as a zone substation (C4) and is fully compliant with our security criteria (refer to 6.1.2). Major loads supplied by this substation include the Pukekohe town centre.

Figure 6-8 below shows the Rural-Urban Boundary (RUB) map for the Pukekohe Zone Substation supply area, outlining the areas for future growth (green boundary line).

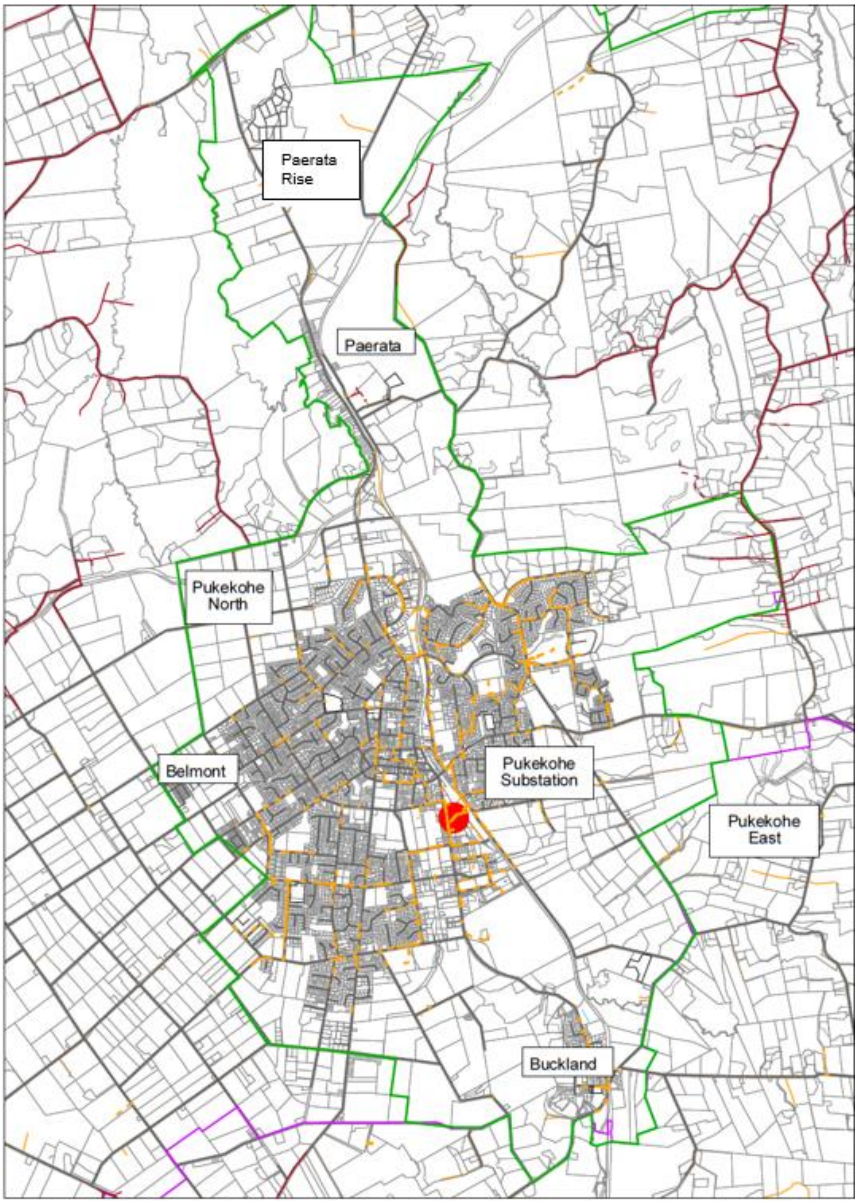


Figure 6-8 Pukekohe Zone Substation supply area

The Pukekohe load has a winter peak. The forecast peak demand for Pukekohe Zone substation and the distribution feeders from the substation is shown in Table 6-9.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Anchor Factory	4.8	4.9	4.7	5.6	6.5	7.4	8.3	9.1	10.0	10.9	11.8	12.7	13.6	14.4	15.3	16.2	15.7%
Buckland	2.9	3.0	3.0	3.1	3.1	3.2	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.7	3.7	3.8	2.0%
Cape Hill	7.2	9.5	9.7	9.9	10.2	10.4	10.6	10.8	11.1	11.3	11.5	11.7	12.0	12.2	12.4	12.6	5.1%
Pukekohe East	1.7	1.7	4.9	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.1	14.0%
Pukekohe Hill	6.6	6.7	6.8	6.8	6.9	7.0	7.0	7.1	7.2	7.2	7.3	7.4	7.4	7.5	7.6	7.6	1.0%
Pukekohe Town	4.9	4.9	5.0	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.5	5.6	5.6	1.0%
Pukekohe West	7.0	7.2	7.3	7.3	7.4	7.5	7.5	7.6	7.7	7.8	7.8	7.9	8.0	8.0	8.1	8.2	1.1%
Railway	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.6	3.7	3.7	3.7	3.8	3.8	1.0%
Titimauku	3.6	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.9	3.9	4.0	4.0	4.0	4.1	4.1	4.1	1.1%
Zone Substation	**Max. Dmd (MVA)**	**Projected Maximum Demand (MVA): Winter Peak**															**Avg. Annual Increase %**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	
Pukekohe	37.2	39.8	42.9	44.2	45.5	46.7	48.0	49.3	50.6	51.9	53.1	54.4	55.7	57.0	58.2	59.5	4.0%

Table 6-9 Winter Maximum Demand at Pukekohe Zone Substation and Feeders

Pukekohe Zone Substation Investment

The Pukekohe Zone Substation demand forecast is shown in Figure 6-9.

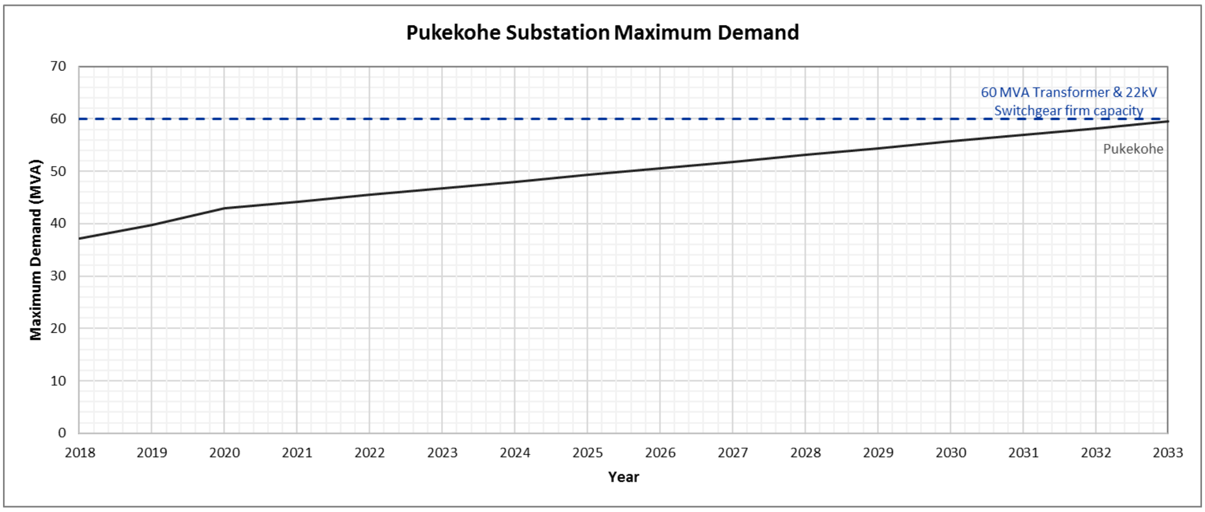


Figure 6-9 Pukekohe Zone Substation Demand Forecast

Two 110/22kV, 30/60MVA transformers supply the load at Pukekohe providing N-1 capacity of 60MVA. The 22kV switchboard supplying the load at Pukekohe also has a capacity of 60MVA. The Pukekohe maximum winter demand is forecast to exceed the transformers' N-1 and switchboard capacity beyond 2032 or 2027 depending on how future urban developments are supplied, discussed later in this section.

The Future Urban Land Supply Strategy 2017 (FULSS) published by Auckland Council in July 2017 has zoned areas north (6,350 lots) and south of Pukekohe (7,200 lots) urban and future urban. Pukekohe north is expected to grow first, followed by Pukekohe south over the planning period.

The Auckland Council has zoned areas surrounding Pukekohe and Paerata as future urban zone in the Auckland Unitary Plan. As part of the urbanisation of Pukekohe and Paerata areas, a large town centre is being built on land that used to be owned by Auckland's Wesley College. This development will be called Paerata Rise. This development is expected to house 4,550 dwellings with a local retail and services centre. There is a future stage of 1,800 dwellings. The first lots from stage 1 have supply agreements already in place. We expect the town could, beyond 15 years, contribute up to 21MVA of load to our network given a typical mix of residential, commercial and retail use.

The proposed investment is to supply the early stages of the Paerata Rise development in the short term (to 2022) from existing feeders from the Pukekohe substation. This will require an upgrade to the Patumahoe feeder to provide backfeed to the development at an estimated cost of $540,000.

For the later stages in the medium to long term (2022/23 onwards) two options of supply were considered.

Option 1 – Extend and increase Pukekohe Zone Substation Capacity, install additional 22kV feeders

This option would consist of the following at the existing Pukekohe Zone Substation to raise firm capacity above 60MVA for N-1 events:

- Increase the transformer capacity at Pukekohe by installing an additional 110/22kV 30/60MVA transformer, taking the firm (N-1) capacity to 120MVA, with an estimated cost of $2 million; and
- Extend the control room at the substation to make provision for a third 22kV bus, and install a new 22kV switchboard and related equipment, with an estimated cost in the order of $3 million.

This option would introduce a number of HILP risks, namely the common mode failure of the 22kV switchboard, the vulnerability due to a fire or explosion in the outdoor yard, the risk of targeted vandalism and the risk of an incident when plant is out of service for maintenance.

Our security of supply and planning guidelines note the risks of having very large numbers of customers supplied from a single zone substation and future developments are planned to utilise two 40MVA transformers which will supply around 15,000 domestic customers. Utilising the full 60MVA firm capacity at Pukekohe would supply over 21,000 customers. Installing a third 60MVA transformer would allow the supply of some 43,000 customers. The impact on SAIDI and SAIFI of an outage with such customer numbers is very significant.

This option is therefore not considered desirable and has not been investigated further.

Additionally, as the largest areas of growth are to the north of Pukekohe, additional feeder capacity would incur a high cost given the distance (Pukekohe Zone Substation is to the south of the town). The costs of these reinforcements will need to be added to the subtransmission costs noted above. Preliminary investigations have indicated that feeder reinforcement from Pukekohe to the Northern area would involve up to four new feeders costing in the order of $3.5 million per feeder (including cable easement costs to diversify feeder routes).

Option 2 – Development of a new 'Pukekohe North' substation

This option would develop a new 110kV/22kV Zone Substation to the north or north east of Pukekohe, providing supply into Pukekohe North, Paerata, and the Paerata Rise Special Housing Area.

This option has an estimated cost in the order of $26 million, which is a higher cost, and added complexity given the need for new 110kV subtransmission corridors and new distribution feeder configurations. It does however provide a number of advantages over extension of the existing Pukekohe substation, specifically:

- Closer to the load centres of Paerata Rise and the future northern development areas;
- Releasing of capacity at Pukekohe to accommodate more localised growth;
- Diversity of supply and provision of interconnection into Pukekohe; and
- Improved resilience against HILP events.

With the target numbers of customers per feeder (1,500) the number of lots (over 6,000) will need at least four feeders. This can be easily accommodated from a new Pukekohe North substation but would be uneconomical from the existing Pukekohe substation, as well as facing difficulty in finding additional line routes.

- The option to install dedicated high capacity trunk feeders from an upgraded Pukekohe substation and develop a switching station in the Paerata Rise and Paerata area located north of Pukekohe, after 2029, has been investigated. It has an estimated cost in the order of $7.9 million but has been ruled out because, based on Council land zoning, the total development load is ultimately expected to grow to around 21MVA and at that scale a new substation is necessary.
- The proposed Pukekohe North substation is strategically situated to support Karaka, Pukekohe, Drury South and Opaheke substations and will help with network resilience.
- The Auckland Future Urban Land Supply Strategy 2017 (FULSS) states that of the total future urban land area in the south of Auckland comprising of Opaheke-Drury, Drury West, Hingaia and Drury South make up 23,400 lots. The load for these dwellings with associated services and commercial load could be up to 73MVA long term. This load will be shared between the existing Opaheke substation (27MVA peak), Drury South substation and the proposed Pukekohe North substation.

Thus, the preferred option is to establish Pukekohe North and utilise the existing Pukekohe substation to meet the growth in its immediate vicinity.

We considered the following alternative development options:

- Localised energy storage or distributed generation to reduce the peak demand under N-1 scenarios, however this option is presently quite costly for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

Pukekohe Zone Substation Feeder Investment

We expect significant residential growth in the area currently supplied by Pukekohe substation through the planning period.

- The Northern Pukekohe area includes the Paerata Rise Special Housing Area of 4,500 dwellings (Anchor Factory Feeder). The Paerata Rise development has announced the first stage of 335 lots, and the potential for further development of around 4,000 lots in future. Indications are that this will only be developed at a rate of 200 dwellings per year, however there is uncertainty around the uptake rates. Subdivision at Paerata Rise outside the SHA is also expected to occur;
- Paerata remainder development of 1,800 lots urban zone expected to come live by 2022;
- The Valley Road area (Cape Hill Feeder) continues to be subdivided, 700 lots are proposed in the Belmont development (Pukekohe West Feeder), and the Pukekohe Hill area has just

commenced subdivision development. From 2020, further subdivision in the East of Pukekohe (Cape Hill and Buckland Feeders) and in the South (Buckland Feeder) can be expected based on planning information we have received; and

- Pukekohe south development of 7,200 lots urban zone expected to come live by 2027.

Figure 6-10 shows the demand forecast for Pukekohe substation feeders.

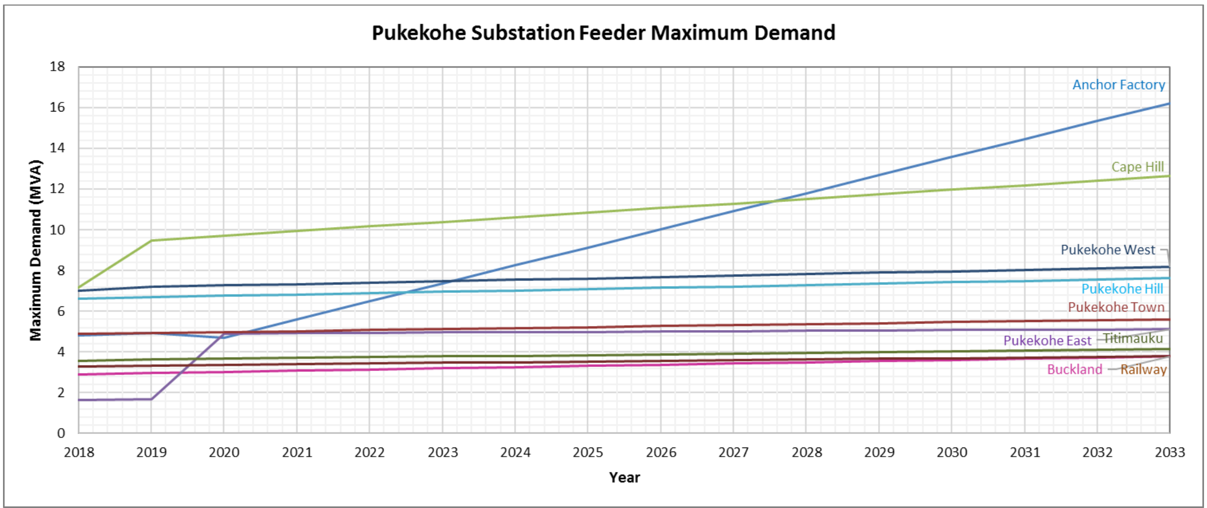


Figure 6-10 Feeder Demand Forecast at Pukekohe Zone Substation

Our development plan for Pukekohe Zone Substation Feeders is as follows to address the capacity constraints identified.

- Install a recloser on Railway feeder to improve supply reliability in 2019/20, at an estimated cost of $35,000. This need will be addressed as part of network performance works;
- Upgrade sections of Anchor Factory and Pukekohe East feeders to transfer industrial load from Anchor Factory to Pukekohe East in 2019/20, at an estimated cost of $460,000;
- Following momentary voltage sags experienced by key customer as a result of faults on the rural feeders at Tuakau and Pukekawa substations we are installing earthing transformers at Tuakau substation for improvement of power quality. Similar units will be installed at Pukekohe substation in 2019/20, at an estimated cost of $550,000 (see Section 6.4.6 for further details);
- Utilise existing sectionalisers and upgrade conductors on urban feeders to transfer high density of residential load from rural feeder sections in 2020/21, at an estimated cost of $50,000;
- Upgrade 300kVA autotransformers to 750kVA on Anchor Factory feeder along Ostrich Farm Road and Schlaepfer Road to address rating constraints in 2022/23, at an estimated cost of $130,000;
- Install a new 22kV feeder section and ring main unit to split front end of Cape Hill feeder in 2023/24, at an estimated cost of $750,000. This need will be addressed as part of network performance works to meet the new customer number target;

- Underground a section of Pukekohe Hill feeder along Kitchener Road to improve reliability in 2023/24, at an estimated cost of $300,000;
- Install a new 22kV feeder section and ring main unit to split front end of Cape Hill feeder in 2023/24, at an estimated cost of $750,000; This need will be addressed as part of network performance works to address the new customer number target;
- Rebuild section of Pukekohe Town feeder along Tobin Street as an underground section to improve reliability in 2023/24, at an estimated cost of $500,000;
- Install a new 22kV feeder section and ring main unit to split front end of Pukekohe West feeder in 2023/24, at an estimated cost of $800,000. This need will be addressed as part of network performance works to reduce customer numbers on this feeder; and
- Upgrade 700m of copper and 350m of swan conductor section of Anchor Factory feeder to backfeed Pukekohe Hill feeder in 2024/25, at an estimated cost of $280,000.

Summary of Pukekohe Development Plan

Description	Scope	Timing	Estimated Costs ($'000)
Improve supply reliability for Railway feeder	Install recloser on Railway feeder	2019/20	35
Increase Pukekohe East and Anchor Factory feeder supply capacity	Upgrade 780m of Robin, 489m of swan and 405m of Robin along Belgium Road, Cape Hill Road and Paerata Road	2019/20	460
Pukekohe power quality	Earthing transformer to address power quality issues at Pukekohe	2019/20	550
Improve supply reliability for residential load on rural feeders	Utilise existing sectionalisers and upgrade conductors on urban feeders to connect rural feeder section with high density of residential load.	2020/21	50
Anchor Factory feeder autotransformers upgrade	Upgrade autotransformers on Ostrich farm road and Schlaepfer road	2022/23	130
Additional 22kV feeder section on Cape Hill Feeder	Install a new 22kV feeder section to split front end of Cape Hill feeder	2023/24	750
Improve reliability of Pukekohe Hill feeder	Underground 600m of overhead section along Kitchener road	2023/24	300
Improve reliability of Pukekohe Town feeder	Underground 600m of overhead section along Tobin street	2023/24	500
Additional 22kV feeder section on Pukekohe West feeder	Install a new 22kV feeder section to split front end of Pukekohe West feeder	2023/24	800
Increase Anchor Factory feeder backfeed supply capacity	Upgrade 600m of Copper along Foy road and 350m of swan along Heights road	2024/25	280

Table 6-10 Summary of Pukekohe Development Plan

Pukekohe North Zone Substation

The Paerata Rise development creates significant load growth forecast to approach 20MW over the planning period.

Further north west to Paerata Rise is the Karaka North area zoned by Auckland Council as a rural settlement. Centred at the intersection of Dyke, Blackbridge and Linwood Road, this settlement is expected to add up to 744 lots over the planning period, contributing to a load of 2.6MVA.

To cater for the uncertainty in rate of uptake in the housing developments in the Paerata Rise and to a smaller extent Karaka North we have assumed that the development will happen at a uniform rate over the coming planning period. An annual increase of 1.4MVA per annum has been chosen up to approximately 23MVA in 2033.

Previously the option to extend the existing Pukekohe substation switchboard and install new feeders from there either as distribution feeders or as trunk feeders to a switching station at the development was considered for the Paerata Rise area. Supply for Karaka North would have been from Karaka substation by converting a feeder to 22kV. Following the discussion in section 6.4.5, the preferred solution is now to supply the Paerata Rise and Karaka North developments by establishing a new zone substation in the Pukekohe North area closer to the development.

Proposed investment

Our proposed investment is to build a new 110/22kV 2x20/40MVA Pukekohe North Area Substation to supply the Paerata Rise and Karaka North housing developments anticipated load south of the Auckland City Rural Urban boundary. This new substation would supply the developments, reducing the reliance on Pukekohe and Karaka substations and existing rural distribution feeders not suited to supply high density urban loads without significant upgrades, and will provide supply diversity.

Our network development plan allows for this proposed new 110kV Pukekohe North Area Substation to be supplied from the Drury South substation that is supplied directly from the proposed new Drury GXP. The development will be staged with a single 110kV line built initially and the second line added when the load reaches 20MVA. The proposed investment represents the optimum long term solution when considering factors including value, security of supply and customer experience.

A 110kV line will be built from Drury South substation to Pukekohe North substation site. An interim solution to defer the substation establishment will be to operate the 110kV line at 22kV to supply Paerata Rise switching station made up of multiple outdoor ring main units. This is dependent on Drury South substation establishment to supply 22kV.

If Drury South substation is not established before the 22kV supply to Paerata Rise is required, then a 110kV supply will be established at Drury GXP. Under this option a single 110kV line will initially be built supplying a 2x 20/40MVA zone substation, with a second line to follow.

Refer to Figure 6-16 for the proposed subtransmission single line diagram for the proposed new Pukekohe North area substation and 110kV supply from the proposed new Drury South substation.

Our development plan for proposed 110kV Pukekohe North Area Substation is to:

- Purchase land for the substation development in a location suitable for whichever transmission supply option we choose to progress, we have allocated $2.3 million for this and plan to acquire the site in 2019/20;

- Secure 110kV line routes for the Pukekohe North Area Substation at an estimated cost of $1.5 million in 2020/21;
- Build 8.7km of 110kV line from Drury South substation to Pukekohe North substation site at an estimated cost of $7.4 million in 2025/26;
- Cable 4km of existing Anchor Factory feeder section from the Pukekohe North substation to Paerata Rise development and a new ring main unit to create backfeed point between Pukekohe and Pukekohe North substation feeders near the development in 2026/27, at an estimated cost of $2 million;
- Cable a 1km section of the existing Blackbridge feeder from the Pukekohe North substation to Karaka North development. Install a new ring main unit to create backfeed point between Karaka and Pukekohe North substation feeders near the development in 2026/27, at an estimated cost of $600,000; and
- Establish a new Pukekohe North area substation at a cost of $17,600,000 in 2028/29 and 2029/30.

The following table summarises the proposed Pukekohe North substation development plan.

Description	Scope	Timing	Estimated Costs ($'000)
Pukekohe North Area Substation land acquisition	Procure land for the establishment of Pukekohe North Area Substation	2019/20	2,300
Pukekohe North Area Substation 110kV line routes	Secure 110kV line routes to supply Pukekohe North Area Substation	2020/21	1,500
Pukekohe North Area Substation 110kV line	Build 110kV line to supply Pukekohe North Area Substation	2025/26	7,400
New feeder from Pukekohe North Area substation	Install 4km of cable from substation to Paerata Rise	2026/27	2,000
New feeder from Pukekohe North Area substation	Install 1km of cable from substation and connect to Blackbridge feeder to Karaka North	2026/27	600
Pukekohe North Area Substation establishment	Build a new Pukekohe North Area Substation with two 110/22kV 40MVA transformers and 22kV switchboard	2028/29-2029/30	17,600

Table 6-11 Pukekohe North substation development plan

6.4.6 Tuakau Zone Substation

The Tuakau 110/22kV Zone Substation is supplied by two 110kV circuits from Bombay GXP, of which one is directly connected to Bombay and the other is connected via Pukekohe.

The Tuakau Zone Substation supplies 768 distribution substations in the urban areas of Tuakau, Church Corner, and River Road and the rural areas of Port Waikato and Whangarata. The load is predominantly residential in the Church Corner, Port Waikato and Tuakau areas. The Pukekawa and Pukekawa Trunk Feeders from Tuakau supply the Pukekawa switching station which in turn supplies the Churchill Road, Glen Murray and Onewhero feeders. Tuakau is classed as a zone substation (C4) and is fully compliant in accordance with our security criteria (refer to 6.1.2).

Tuakau and Pukekawa supply three of our largest customers, Yashili Dairy, Watercare Waikato Water Treatment Plant and Envirowaste's landfill and generators at Hampton Downs.

The Tuakau residential load is winter peaking. The River Road and Whangarata feeder loads will peak at any time due to industrial loads (processing and quarrying). The forecast peak demand for Tuakau substation and the distribution feeders from the substation is shown in Table 6-12.

22kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Church Corner	1.9	2.0	2.0	2.3	2.3	2.3	2.4	2.4	2.5	2.5	2.5	2.6	2.6	2.6	2.7	2.7	2.8%
Port Waikato	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.0%
River Road	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.7	2.8	2.0%
Tuakau	3.5	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.1	4.2	4.3	4.3	4.4	4.5	4.6	2.0%
Whangarata	3.0	4.1	4.3	4.4	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.9	4.9	5.0	5.0	5.1	4.8%
WWTP 1	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	1.0%
WWTP 2	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	1.0%
Hitchen Road	3.2	10.7	10.7	10.8	10.8	13.3	13.4	13.4	13.4	13.4	13.5	13.5	13.5	13.6	13.6	13.6	22.1%
Tuakau Industrial	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.9	0.9	1.0	1.0	1.1	1.2	7.9%
Potter Road	0.0	3.4	6.4	10.4	15.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	0.0%
Pukekawa	3.6	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.9	2.3%
Pukekawa Trunk	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Zone Substation	**Max. Dmd (MVA)**	**Projected Maximum Demand (MVA): Winter Peak**															**Avg. Annual Increase %**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	
Tuakau with Generation	16.5	26.1	16.3	16.7	16.9	17.1	17.4	17.6	17.8	18.0	18.3	18.5	18.7	19.0	19.2	19.5	1.2%
Hampton Downs Generation	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	0.0%
Tuakau without Generation	22.0	31.6	21.8	22.2	22.4	22.6	22.9	23.1	23.3	23.5	23.8	24.0	24.2	24.5	24.7	25.0	0.9%
Pokeno			17.1	21.2	26.2	35.7	37.2	38.6	40.1	41.6	43.0	43.1	43.1	43.1	43.2	43.2	10.9%

Table 6-12 Winter Maximum Demand at Tuakau Zone Substation and Feeders

Tuakau Zone Substation Investment

The Tuakau Zone Substation demand forecast is shown in Figure 6-11 below.

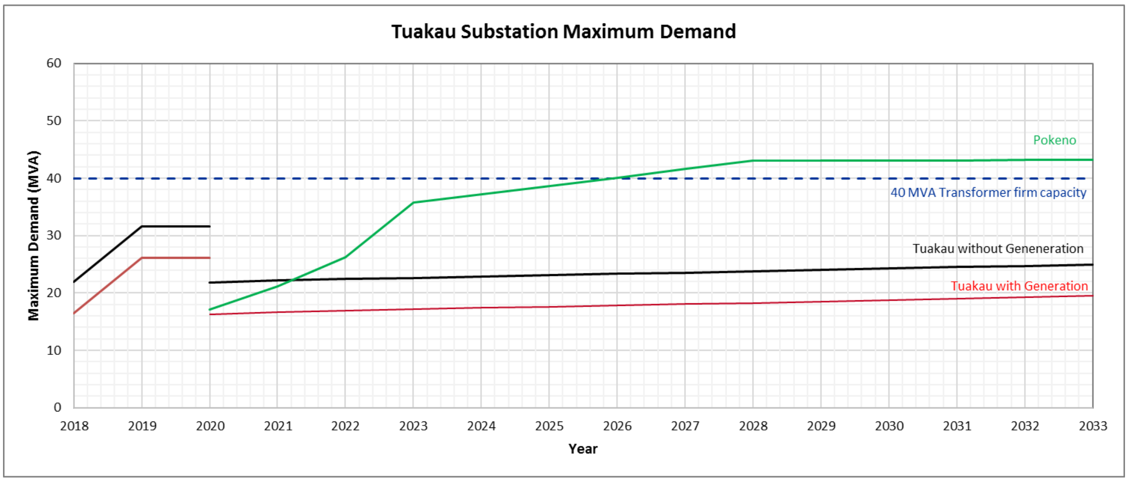


Figure 6-11 Tuakau Zone Substation Demand Forecast

Two 110/22kV, 20/40MVA transformers supply the load at Tuakau providing N-1 capacity of 40MVA. Note that with the establishment of Pokeno zone substation (as discussed in Section 6.4.3), a significant amount of the load shown above will be supplied from there rather than Tuakau zone substation after 2020.

Tuakau Zone Substation Feeders Investment

We expect significant growth in the area through the planning period including:

- Continued residential subdivision developments in the Hitchen Road area and other Pokeno subdivisions;
- Expansion of the Waikato Water Treatment Plant and the Pokeno residential subdivisions; and
- New load connections in the Pokeno industrial area.

Note that the majority of this load growth is in the Pokeno area and is driving the need for a zone substation in Pokeno as discussed in Section 6.4.3.

Figure 6-12 shows the demand forecast for Tuakau substation feeders.

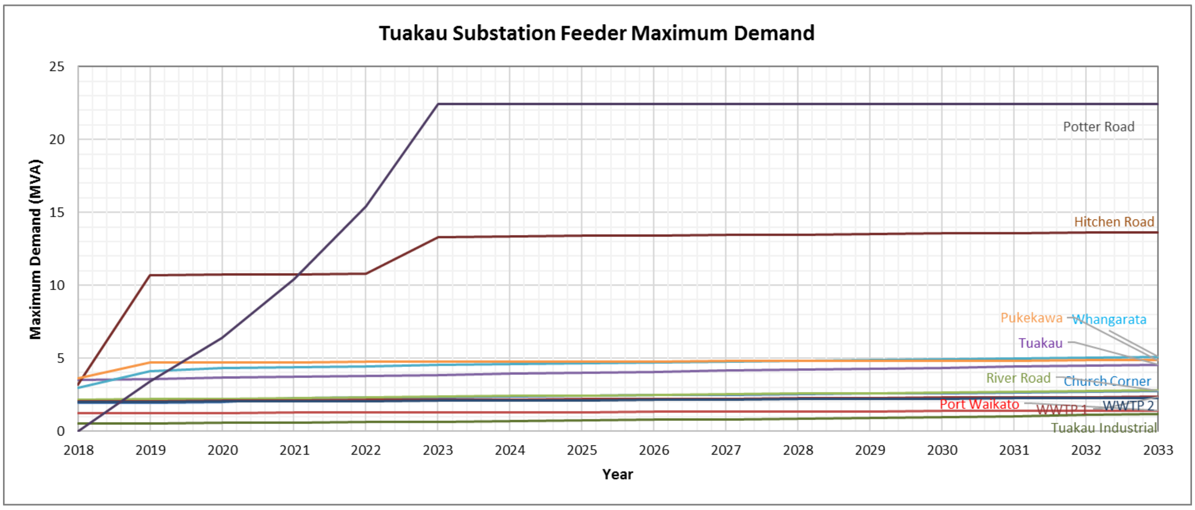


Figure 6-12 Feeder Demand Forecast at Tuakau Zone Substation

Figure 6-13 shows the demand forecast for Tuakau substation feeders without feeders supplying load to be supplied by Pokeno zone substation (as discussed in Section 6.4.3).

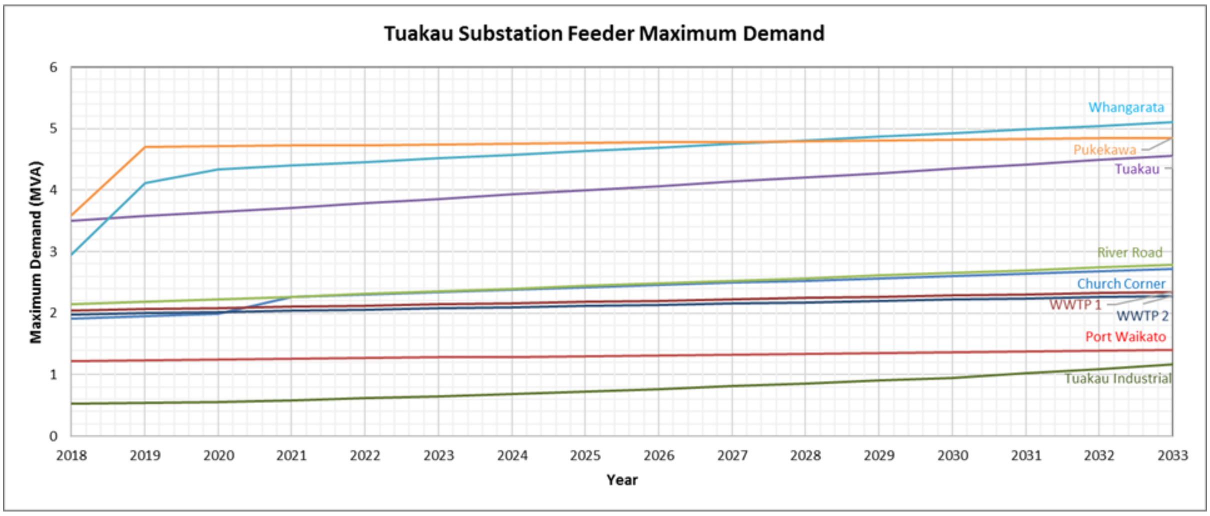


Figure 6-13 Feeder Demand Forecast at Tuakau Zone Substation without Pokeno

Our development plan for Tuakau Zone Substation Feeders which is in progress include:

- Complete establishment of Pukekawa Trunk feeder to Pukekawa switching station in 2019/20, at an estimated cost of $690,000;

- Upgrade auto-transformers and install voltage regulators on Port Waikato feeder to increase backfeed capacity in 2019/20, at an estimated cost of $200,000;
- Replace ABS140 on Whangarata feeder with an automated switch to improve network performance in 2019/20 at an estimated cost of $35,000;
- Replace ABS189 and ABS222 with automated switches to improve network performance in 2019/20 at an estimated cost of $70,000; and
- Upgrade auto-transformers and install voltage regulators on Glen Murray feeder to increase backfeed capacity in 2021/22, at an estimated cost of $400,000.

Several industrial consumers connected to Tuakau have previously experienced some momentary voltage sags as a result of faults on the rural feeders from Tuakau and Pukekawa substations. We have since investigated options to improve power quality and reduce the impact of dips and sags on the substation bus voltage. The investigation found that installation of earthing transformers with neutral earthing resistors would be the most cost effective, practical and timely solution.

This was completed at Tuakau in 2018. Similar projects are scheduled for Opaheke and Pukekohe in the 2019/20 financial year.

Battery Energy Storage Trial

One of the network alternative technologies which has the potential to change how distribution networks traditionally operate is energy storage through the use of grid scale battery storage system.

We installed our first grid-scale battery storage system at the Tuakau Zone Substation in 2017. This trial installation is to understand the benefits such systems can provide including management of peak demand, contributing to quality of supply in our network through reactive power support, and to provide ancillary services. While the battery trial has specific objectives, it will more broadly enable better understanding of its impact on the network, its limitations, and the benefits it can provide across the whole network over time.

We see value in the following areas:

- **Peak Demand Management and Reduction** – savings in Transmission Peak Costs;
- **Voltage Support** – the battery, with the appropriate control systems, could be used to assist with voltage support, improving the power quality at Tuakau;
- **Energy Storage** – charge the batteries at lower off-peak rates and discharge at peak times; and
- **Ancillary Services Market** – battery storage may be suitable for instantaneous reserves.

At the time of writing this AMP, we consider the battery to be able to provide both regulated benefits (in terms of network support and peak demand management on the distribution network), as well as unregulated benefits (such as value from the arbitrage of energy when not used for regulated purposes). As such we discuss the use of the battery in this AMP in the context of our regulated activities however we are working to develop a cost allocation methodology to provide a transparent means of reporting how we use the battery and allocate respective costs and benefits.

Summary of Tuakau Development Plan

Description	Scope	Timing	Estimated Costs ($'000)
Pukekawa Trunk feeder	Complete establishment of Pukekawa Trunk feeder to Pukekawa switching station	2019/20	690
Increase Port Waikato feeder backfeed capacity	Upgrade auto-transformer and install voltage regulator on Port Waikato feeder	2019/20	200
Improve Whangarata feeder network performance	Replace ABS140 with an automated switch	2019/20	35
Improve Port Waikato feeder network performance	Replace ABS189 and ABS222 with automated switches	2019/20	70
Increase Glen Murray feeder backfeed capacity	Upgrade auto-transformer and install voltage regulator on Glen Murray feeder	2021/22	400

Table 6-13 Summary of Tuakau Development Plan

6.4.7 Mangatawhiri and Ramarama

Mangatawhiri and Ramarama substations supply the eastern areas of our network from Kaiaua, Paparata and Ararimu in the north to Mercer in the south.

The Mangatawhiri 33/11kV Zone Substation is supplied by one 33kV circuit from Bombay GXP. Mangatawhiri Zone Substation supplies 446 distribution substations in the rural areas of Kaiaua, Mercer, Paparata and Pokeno Church. The load is predominantly rural residential. Mangatawhiri is classed as a small zone substation (C3) and is fully compliant in accordance with our security criteria.

The Ramarama 33/11kV Zone Substation is supplied by two 33kV circuits from Bombay GXP. Ramarama Zone Substation supplies 355 distribution substations in the rural areas of Ararimu, Bombay and Great South Road. The load is predominantly rural residential. Ramarama is classed as a medium zone substation (C3) and is fully compliant in accordance with our security criteria.

Options considered

Supply assets are at end of life

We are the primary user of the 33kV assets Transpower operates at the Bombay GXP. These assets are at end of life and will be subject to policy replacement projects by Transpower around 2020.

This work would include the following renewal activities:

- Replacement of outdoor 33kV switchgear, circuit breakers and bus structure;
- Replacement of two 110/33kV supply transformers with 110/33kV or 110/22kV transformers; and
- Replacement of associated secondary equipment.

Additionally, we have assets that are also at end of life, particularly:

- The Bombay 33kV ripple injection plant;
- The Mangatawhiri 33kV line, including poles, crossarms and conductors;

- The Mangatawhiri 33/11kV substation;
- The Ramarama 33kV line is supported on end of life steel towers, which will require replacement and the line corridor is one route that a new 110kV line to supply Drury South Business Park could use; and
- The Ramarama 33/11kV substation is small, and unsuitable for supply to large growth in the area – this will be better accommodated by a new Drury South Area Substation to supply the Drury South Business Park.

We considered the following options to maintain supply to customers supplied from Mangatawhiri and Ramarama substations:

- Option 1: Rebuild Mangatawhiri and Ramarama substations. This would involve like for like rebuild at an estimated cost of $8m; or
- Option 2: Establish new Bombay area zone substation. This would involve establishing a new 110/22kV substation in the vicinity of Bombay GXP and feeder reinforcement to provide connection to existing feeders. The estimated cost of this option is $12.7m; or
- Option 3: Supply from Drury South substation (see 6.4.2) and Pokeno substation (see 6.4.3). This would utilise proposed substations at Drury South and Pokeno and would include installation of an additional transformer and 22kV bus section at each substation to provide segregation between industrial and rural feeders. The estimated cost of this option is $18.9m; or
- Option 4: Rebuild Mangatawhiri substation and use Drury South substation. This would involve a like for like rebuild of Mangatawhiri substation and utilise the proposed Drury South substation to supply feeders presently supplied from Ramarama substation. The estimated cost of this option is $8m; or
- Option 5: Rebuild Ramarama substation and use Pokeno substation. This would involve a like for like rebuild of Ramarama substation and utilise the proposed Pokeno substation to supply feeders presently supplied from Mangatawhiri substation. The estimated cost of this option is $14.2m.

We have also considered the alternative non-network options.

- Use of localised energy storage or distributed generation. However, this option is, at present, costly for the level of utilisation and required capacity to supply the existing load supplied from Mangatawhiri and Ramarama substations. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of investment planning process.

We considered the alternative of retaining the existing 33kV supply to Mangatawhiri and Ramarama substations. However, this option would incur significant costs, as most of the existing assets, including the 33kV transmission line to Ramarama, are near the end of their economic life and would need to be replaced within the period of this AMP.

Proposed investment

Our proposed investment is to build a new 110/22kV Bombay area substation to supply load presently fed from Mangatawhiri and Ramarama substations.

This option was chosen because:

- It will rationalise existing assets by standardising on 110kV as subtransmission voltage in the eastern region and 22kV distribution supplies at all eastern region substations;
- It will provide resilience for HILP events at Drury South and Pokeno substations by providing improved feeder interconnections at 22kV; and
- Provide savings in our Annual Operational Charges with Transpower at the Bombay Grid Exit Point and allowing them to remove 33kV supply – rationalising their assets.

The concept of a single, centralised Zone Substation located in the approximate load centre of the supply area is a valid concept based on the number of identified issues at the two zone substations and the Bombay 33kV supply being disestablished (or requiring significant investment to address age and condition). Discussions with Transpower have indicated that co-locating a Counties Power substation at their Bombay GXP is acceptable in principle, subject to agreeing commercial terms.

The project includes:

- Building a new 110/22kV substation on Transpower land adjacent to the Bombay GXP, including connection to the Bombay 110kV bus, to replace the Mangatawhiri and Ramarama substations to supply the load in the area by 2021/22; and
- Connecting existing feeders to the new substation by 2021/22.

The total cost of this option is in the order of $12.7 million. This has been allowed for in our expenditure forecasts.

Mangatawhiri and Ramarama area (Bombay Area Substation) demand forecast

Table 6-14 shows the winter maximum demand forecast for Mangatawhiri and Ramarama substations (to be replaced by a new 110kV substation in 2021/22).

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Ararimu	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	0.7%
Bombay	3.5	3.6	3.7	3.7	3.8	3.9	3.9	4.0	4.0	4.1	4.2	4.2	4.3	4.3	4.4	4.4	1.9%
Great South Road	1.5	1.6	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	3.7%
- Great South Road w/ Drury South SHA	1.5	1.6	2.1	2.6	3.2	3.7	4.3	4.8	4.8	4.8	4.9	4.9	4.9	4.9	4.9	5.0	15.1%
Kaiaua	2.5	2.6	2.6	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.3	2.1%
Mercer	1.5	3.6	3.6	3.6	3.6	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	10.1%
Paparata	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	-1.0%
Pokeno	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.2	6.3	6.4	6.5	6.6	6.7	2.0%
Zone Substation	**Max. Dmd (MVA)**	**Projected Maximum Demand (MVA): Winter Peak**															**Avg. Annual Increase %**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	
Bombay Area	0.0	0.0	0.0	0.0	0.0	14.7	14.9	15.1	15.2	15.4	15.6	15.7	15.9	16.1	16.2	16.4	1.0%
Bombay Area w/ Drury South SHA	0.0	0.0	0.0	0.0	0.0	15.9	16.5	17.0	17.2	17.4	17.5	17.7	17.8	18.0	18.2	18.3	1.4%

Table 6-14 Winter Maximum Demand for Mangatawhiri and Ramarama Substations and Feeders

The Mangatawhiri and Ramarama load is winter peaking and is made up of a mix of commercial and residential load. We anticipate some residential growth around Bombay and on the areas immediately to the north and south along SH1, as far as Pokeno.

Mangatawhiri and Ramarama Zone Substation investment need

Figure 6-14 shows the demand forecast for Mangatawhiri and Ramarama Substations[26]

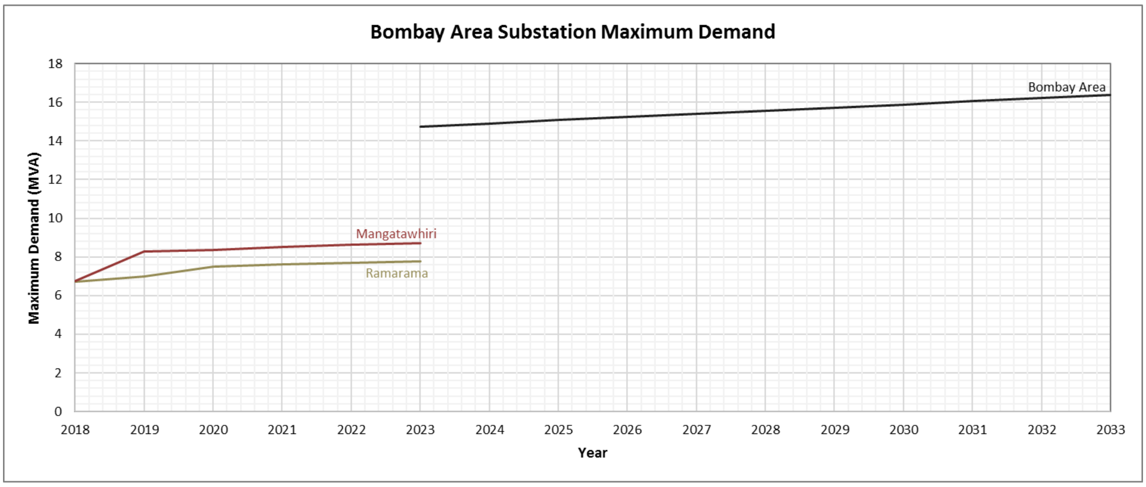


Figure 6-14 Mangatawhiri and Ramarama Substations Demand Forecast

The present supply configuration is made up of:

- One 33/11kV, 7.5MVA transformer supplying the load at Mangatawhiri with no N-1 capacity; and
- Two 33/11kV, 5MVA transformers supplying the load at Ramarama providing N-1 capacity of 5MVA.

Mangatawhiri and Ramarama Zone Substation Feeders investment need

The supply area of Mangatawhiri covers part of the Pokeno area around the State Highway 1 and 2 junctions. We expect significant growth from the Pokeno subdivisions through the planning period.

Figure 6-15 shows the demand forecast for feeders at Mangatawhiri and Ramarama Substations.

[26] The proposed Bombay Area substation replaces Mangatawhiri and Ramarama from 2021/22.

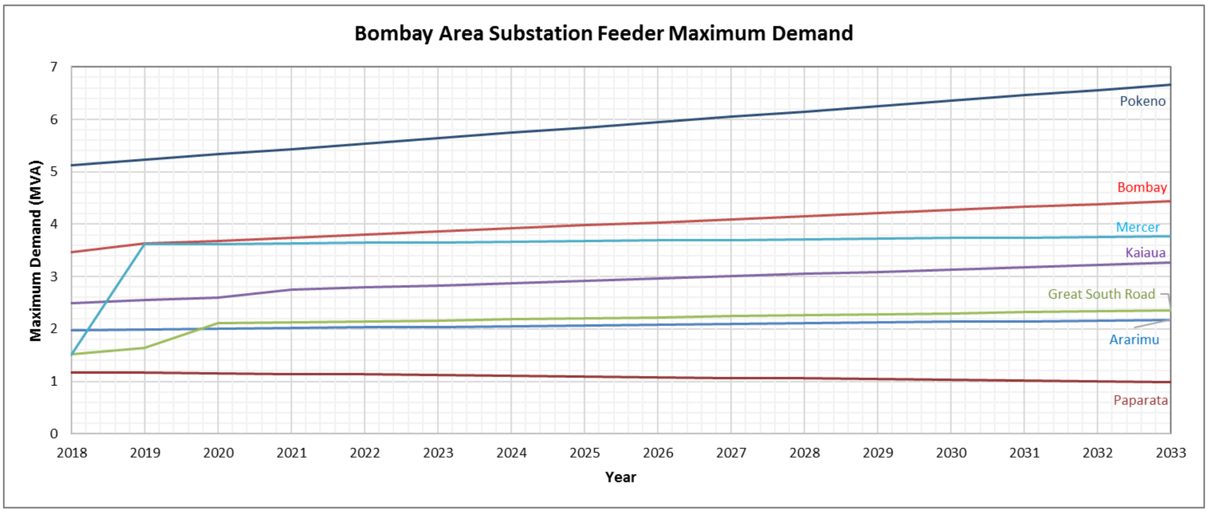


Figure 6-15 Feeder Demand Forecast for Mangatawhiri and Ramarama Substation Feeders

Our planned investment for feeders includes:

- Replace ABS445 on Ararimu feeder with a recloser to improve network performance in 2019/20 at an estimated cost of $35,000;
- 22kV Conversion of Bombay feeder (Ramarama) in advance of establishment of Bombay area substation in 2020/21, at an estimated cost of $3 million;
- Great South Rd feeder conductor upgrade in 2021/22, at an estimated cost of $80,000;
- Conversion of feeders supplied from Bombay area substation to resolve forecast voltage constraints and improve backfeed capacity into the Drury South area at an estimated cost of $9 million in 2022/23 and 2023/24;
- Rebuild a section of Great South Rd feeder to improve network performance in 2023/24 at an estimated cost of $330,000;
- Create link between Mercer feeder and Pokeno Church feeder to increase backfeed capacity in 2025/26, at an estimated cost of $1 million;
- Upgrade conductor in increase backfeed capacity between Whangarata feeder and Bombay feeder in 2027/28, at an estimated cost of $150,000; and
- Kaiaua feeder split to improve security, reduce customers and increase backfeed flexibility in 2028/29, at an estimated cost of $1.8 million.

Summary of Bombay Area Development Plan

Description	Scope	Timing	Estimated Costs ($'000)
Improve Ararimu feeder network performance	Replace ABS445 with a recloser	2019/20	35
Bombay feeder 22kV conversion	Convert Bombay feeder to 22kV operation in advance of Bombay area zone substation	2020/21	3,000
Bombay Area Substation establishment	Construct new substation including transformers, switchgear and protection and control to replace existing Ramarama and Mangatawhiri substations	2021/22	12,700
Great South Rd feeder upgrade	Upgrade 300m of overhead and cable sections along Hillview Rd	2021/22	80
Bombay area substation 22kV feeder conversion	Convert feeders supplied from Bombay area substation to resolve voltage constraints and improve backfeed capacity into the Drury South area	2022/23-2023/24	9,000
Great South Rd feeder rebuild	Rebuild part of Great South Rd feeder to improve network performance	2023/24	330
Increase Mercer/Pokeno Church backfeed capacity	Extend feeders to create a backfeed between Mercer feeder and Pokeno Church feeder	2025/26	1,000
Increase Whangarata/Bombay backfeed capacity	Replace 95 mm^2 cable to increase backfeed capacity between Whangarata feeder and Bombay feeder	2027/28	150
Kaiaua feeder split	Install a new RMU to create a second feeder to Kaiaua to reduce overall customer numbers	2028/29	1,800

Table 6-15 Summary of Bombay Area Development Plan

Figure 6-16 below show the single line schematic for the Future Eastern subtransmission network supplied from the Bombay and Drury grid exit points.

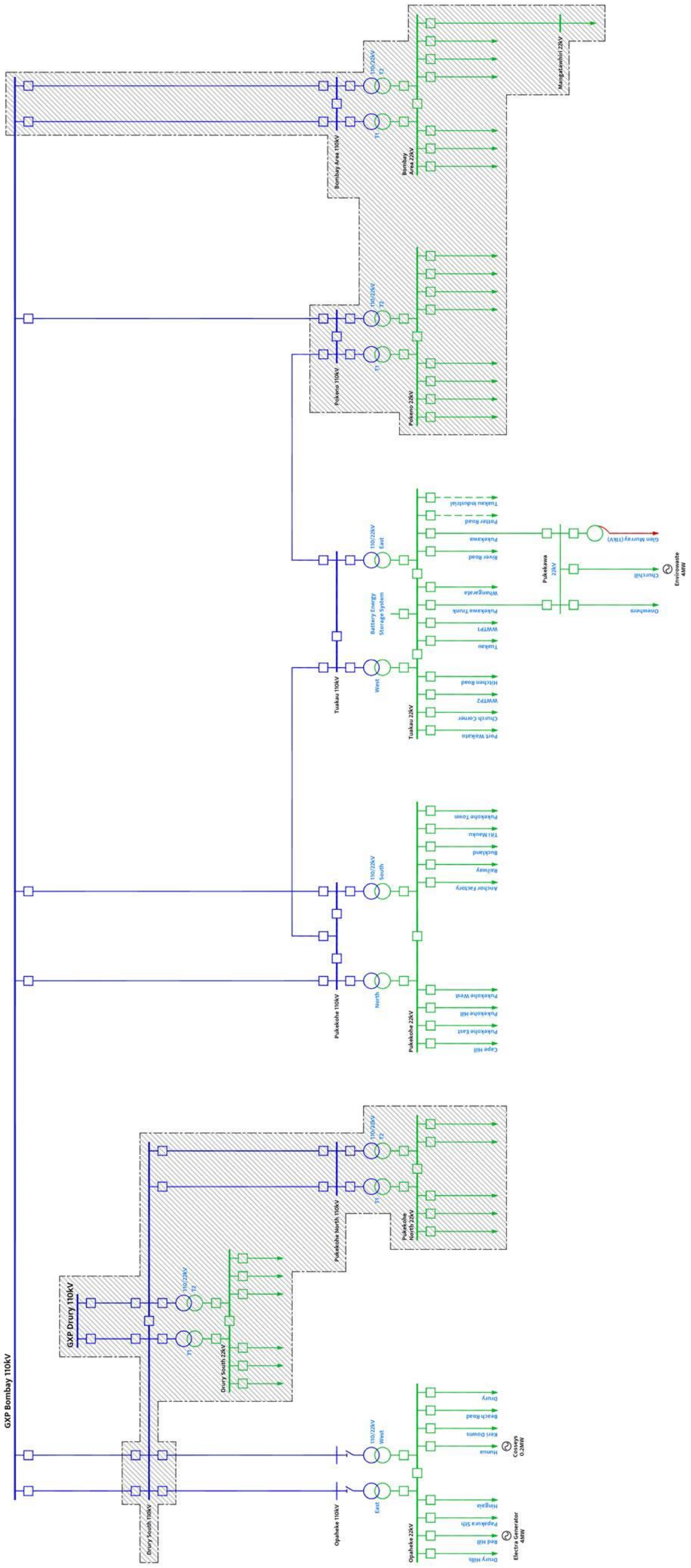


Figure 6-16 Single Line Schematic of the Future Eastern Region 110kV subtransmission network

6.5 Western region development plan

The Western Region is supplied from Transpower's Glenbrook Grid Exit Point and covers areas supplied by our Karaka, Maioro and Waiuku Zone Substations and a 33kV point of supply at Storey Road. Figure 6-17 and Table 6-16 show the total Western Region forecast demand.

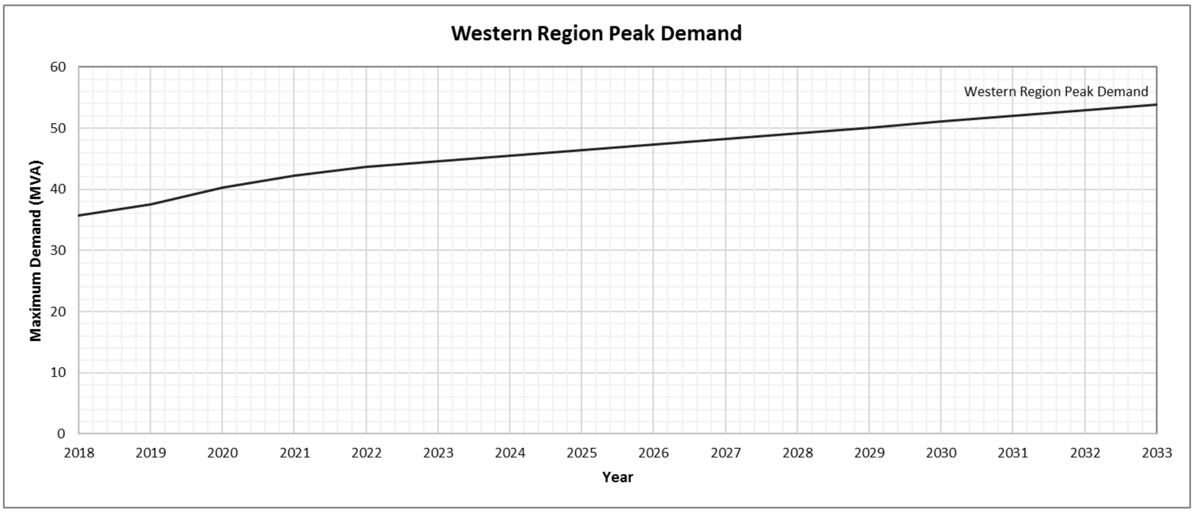


Figure 6-17 Winter Maximum Demand for Western Region

Zone Substation		Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Waiuku	33/11kV	17.4	18.1	18.8	19.4	19.8	20.2	20.6	21.0	21.5	21.9	22.3	22.7	23.1	23.5	23.9	24.3	2.7%
Karaka	33/11kV	11.8	13.6	16.6	18.5	19.6	20.3	21.0	21.7	22.4	23.1	23.8	24.5	25.1	25.8	26.5	27.2	8.8%
Maioro	33/11kV	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	0.1%
NZS (Storey Road)	33/11kV	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	0.0%
Western Region		35.7	37.8	41.0	43.0	44.3	45.3	46.2	47.1	48.0	49.0	49.9	50.8	51.7	52.7	53.6	54.5	3.5%

Table 6-16 Winter Maximum Demand for Western Region

Our subtransmission network in the Western region supplies zone substations and the 11kV distribution network via:

- Two 33kV lines from Glenbrook Grid Exit Point to Waiuku;
- One 33kV line from Waiuku to Story Road Pump Station and Maioro; and
- Two 33kV lines from Glenbrook Grid Exit Point to Karaka.

Figure 6-18 shows the single line schematic for the Western region subtransmission network supplied from the Glenbrook grid exit point.

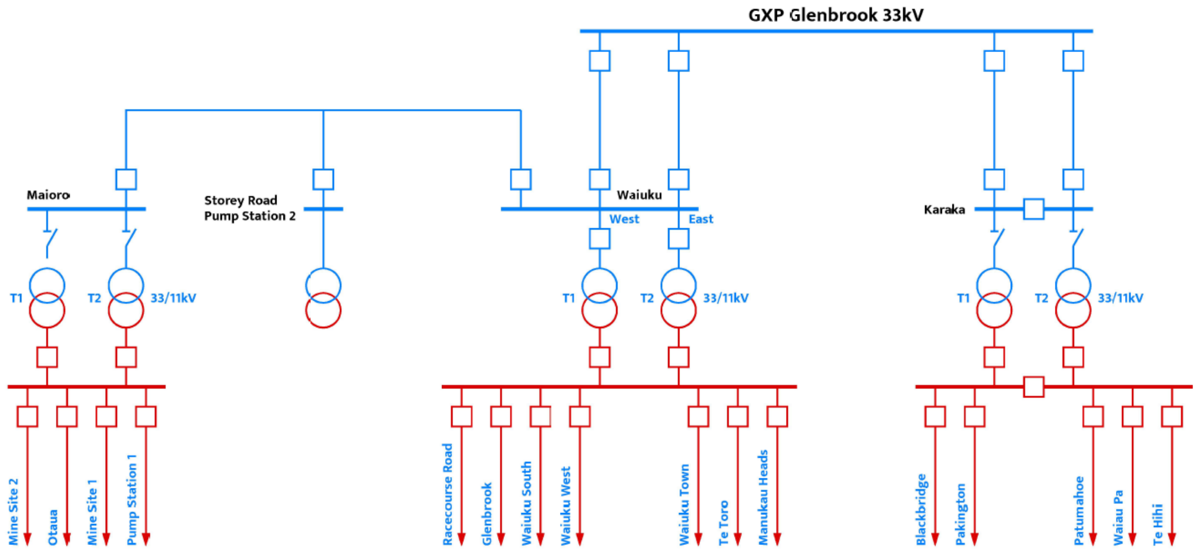


Figure 6-18 Single Line Schematic of the Western Region subtransmission network

This system has the following constraints:

- The distances between the load centres and our substations are too great for efficient 11kV distribution, in particular the distance and demands of Waiau Pa, Clarks Beach and Kingseat from the existing Karaka Substation is too great for 11kV distribution. Similarly, for Glenbrook Beach from Waiuku Substation; and
- The 33kV network is not suitable for connecting any major wind farms[27] to the network, which have previously been consented but not developed. The likelihood of these proceeding during the planning period is very low.

As there is no 110kV supply from Transpower's Glenbrook Grid Exit Point, it would require significant load or generation increase in the area to make it economic to convert to a 110kV subtransmission network and a 22kV distribution network. In the longer term, there are two potential options to increase supply capacity for the area. One option is to continue with the existing 33/11kV network architecture and to upgrade the 11kV to 22kV in places to achieve the required voltage performance on the longer feeders. An alternative is to establish 110/22kV architecture as used in the Eastern Region, however this is harder to achieve as there is no 110kV transmission supply into the area at present.

We expect some growth in the Western region over the next ten years with:

- Designation of special housing accord areas at Glenbrook Beach;
- Proposed developments at Clarks Beach and Kingseat; and
- Subdivisions at Patumahoe, Waiau Pa and Waiuku.

[27] A small windfarm is being developed near Waiuku and there is a possibility that a wind farm may eventuate on the Manukau Heads

The proposed expansion at New Zealand Steel's mine site at Maioro will only have a minor impact on our network.

6.5.1 South Western Subtransmission

South Western Area subtransmission investment requirements

Two 33kV lines from Glenbrook supply Waiuku and the rest of the South Western Area (Maioro and Storey Road). The Waiuku West line is strung with Cockroach conductor (rated at 32MVA). The Waiuku East line is strung with lower rated Cricket conductor (rated at 24MVA) for the total length of the line.

The loading on the 33kV Glenbrook to Waiuku East line exceeded its N-1 capacity (the standard rating for the Cricket conductor section) from 2016 during the peak load period and is forecast to reach 110% of the N-1 rating by 2019. Replacing the Cricket conductor may be able to be deferred if a cyclic rating can be applied to the Waiuku East line. Investigations will be required in 2019/20, at an estimated cost of $300,000 to confirm that there are sufficient clearances on the line to operate with a cyclic rating and to set the rating.

Our proposed investment to address the identified constraint on the Waiuku East line will be developed following the investigations to either reconductor the 33kV East line from Glenbrook to Waiuku with higher rated Cockroach conductor or restring the conductor and define operating limits to defer further investment.

We considered the following alternative development options:

- Transferring load from Waiuku to the adjacent Karaka substation at 11kV to reduce the loading on the substation, and defer the subtransmission investment, however this is not feasible due to voltage constraints on the interconnecting feeders and significant load transfers have occurred (to both Karaka, but also Maioro and Pukekohe) in the past leaving little residual capacity able to be transferred;
- Localised energy storage or distributed generation to reduce the peak demand under N-1 scenarios, however this option is, at present, costly for the level of utilisation; and
- Building a third 33kV line from Glenbrook to Waiuku. However, this project was discounted as the cost would be significantly greater than the alternative solution of reconductoring the existing line and would require extensive substation bus modifications as well as requiring a new line route.

Summary of south western area subtransmission development

Description	Scope	Timing	Estimated Costs ($'000)
Reconductor Glenbrook to Waiuku East line	Investigate options to address capacity constraints on the 7.8km of 33kV concrete pole line in cricket conductor	2019/20	300

Table 6-17 Summary of south western area subtransmission development

6.5.2 North Western Subtransmission

North Western Area subtransmission investment need

Two 33kV lines from Glenbrook supply Karaka. The Karaka North line is strung with Cricket conductor. The Karaka South line is strung with parts of Cricket (24MVA) and parts of lower rated Dog conductor (17.1MVA).

The loading on the 33kV Glenbrook to Karaka South line will exceed its N-1 capacity (the rating for the Dog conductor section) in 2021 during the peak load period and is forecast to reach 110% of the N-1 rating by 2022. Reinforcement can be deferred if a cyclic rating can be applied to the Karaka South line. Investigations will be required in 2021/22, at an estimated cost of $400,000 to confirm that there are sufficient clearances on the line to operate with a cyclic rating.

Our proposed investment to address the identified constraint on the Karaka South line will be developed following the investigations to either reconductor the 33kV South line from Glenbrook to Karaka with higher rated Cricket conductor or restring the conductor and define operating limits to defer investment.

We considered the following alternative development options:

- Transferring load from Karaka to the adjacent Waiuku substation at 11kV to reduce the loading on the substation, and defer the subtransmission investment, however this is not feasible due to voltage constraints on the interconnecting feeders and N-1 capacity constraints on the Waiuku subtransmission lines;
- Localised energy storage or distributed generation to reduce the peak demand under N-1 scenarios, however this option is, at present, costly for the level of utilisation; and
- There is possibility to transfer Karaka load to the potential new Glenbrook Beach substation (refer section 6.5.4) and Pukekohe North substation (refer section 6.4.5), but the timing of either substation establishment will need to be before the revised cyclic rating of the Glenbrook Karaka South line is exceeded. If the timing of the substation establishment can be aligned with the capacity constraint on the Karaka South line, then major investment can be further deferred.

Summary of north western area subtransmission development

Description	Scope	Timing	Estimated Costs ($'000)
Glenbrook to Karaka South line capacity constraint investigations	Investigate options to address capacity constraints on the 13km of 33kV concrete pole line in Dog and Cricket conductor	2021/22	400

Table 6-18 Summary of north western area subtransmission development

6.5.3 Wind Farm development

Resource consent has previously been granted to build a wind farm on the Manukau Heads, however it is not proceeding at this time and the consents have expired. At the time of writing this plan, it has been indicated that windfarm development in the area may commence again in the short to medium term, although no timeframes are known. Should this valuable wind resource be redeveloped during the planning period, it would have a significant impact on subtransmission development in the Western area.

A smaller development is currently underway near Kariotahi which is expected to be able to connect to the local feeder from Waiuku substation.

We will review our options and finalise a development path to connect any other generation in this area in future plans, should the need arise.

6.5.4 Karaka Zone Substation

The Karaka 33/11kV Zone Substation is supplied by two 33kV circuits from Glenbrook GXP. Karaka Zone Substation supplies 459 distribution substations in the mainly rural areas of Blackbridge, Pakington, Patumahoe, Te Hihi and Waiau Pa. The load is predominantly residential. Karaka is classed as a zone substation (C3) and is fully compliant with our security criteria (refer to 6.1.2).

The Karaka load is winter peaking. The forecast peak demand for Karaka Zone substation and the distribution feeders from the substation is shown in Table 6-18.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Blackbridge	1.5	1.6	2.1	2.9	3.1	3.3	3.5	3.6	3.8	4.0	4.1	4.3	4.5	4.7	4.8	5.0	15.6%
Pakington	2.6	2.8	2.8	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.1	3.1	1.2%
Patumahoe	2.2	2.6	3.8	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.2	4.2	4.2	4.3	4.3	4.4	6.8%
Te Hihi	2.6	3.1	3.8	4.6	5.3	5.5	5.8	6.0	6.3	6.5	6.8	7.0	7.3	7.5	7.7	8.0	13.6%
Waiau Pa	3.1	3.4	3.5	3.8	4.0	4.2	4.5	4.7	4.9	5.1	5.4	5.6	5.8	6.1	6.3	6.5	7.2%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Karaka	11.8	13.2	15.8	17.6	18.8	19.5	20.2	20.9	21.5	22.2	22.9	23.6	24.3	25.0	25.7	26.4	8.3%

Table 6-19 Winter Maximum Demand at Karaka Zone Substation and Feeders

Karaka Zone Substation Investment

The Karaka Zone Substation demand forecast is shown in Figure 6-19.

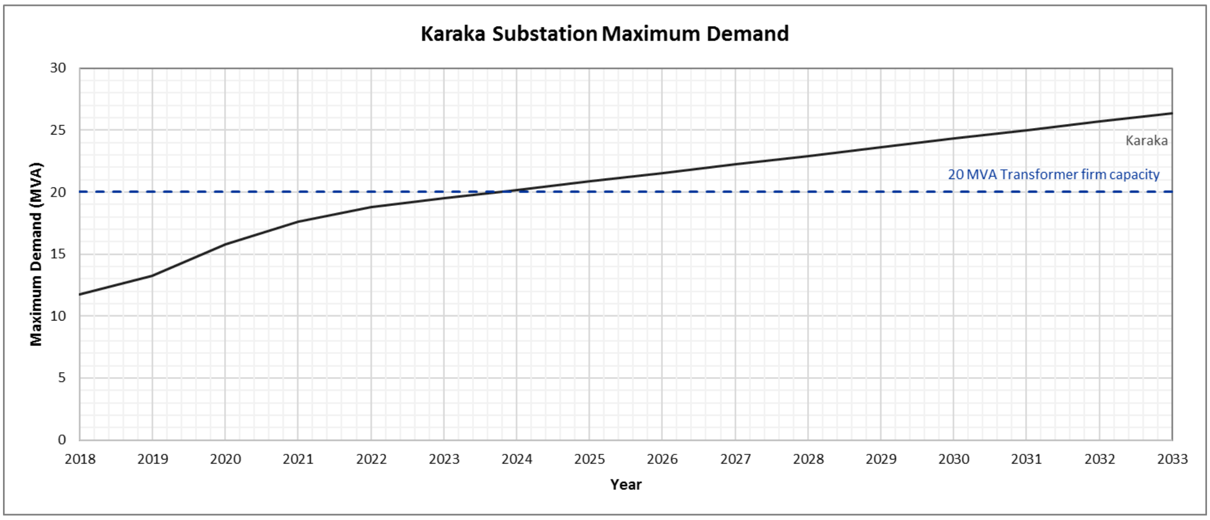


Figure 6-19 Karaka Zone Substation Demand Forecast

There are two 33/11kV 10/20MVA transformers installed at Karaka substation providing a N-1 capacity of 20MVA, which will be exceeded in 2024, the switchboard rating will be exceeded in 2030 which is also when it is at its end of life. We expect significant growth from the Kingseat, Clarks Beach and Karaka North subdivision developments. The Kingseat subdivision has been assumed to incur demand of the first 815 lots over the next 3 years and potentially up to 1,850 lots through the planning period. The Clarks Beach and Karaka North subdivisions are expected to add up to 1,351 lots and 744 lots respectively over the planning period.

Some load from our Waiuku substation has been transferred to Karaka substation to relieve the loading on the 33kV Glenbrook - Waiuku circuits. To accommodate this transferred load, as well as to accommodate additional load on the Karaka substation arising from growth in Glenbrook Beach, Clarks Beach, Karaka North and Kingseat areas, the previous year's asset management plan proposed that Blackbridge, Waiau Pa and Te Hihi feeders' distribution feeders from Karaka be reconfigured and converted to 22kV operation to address the capacity and voltage constraints identified.

However, following the review of network security criteria where the target number of customers per feeder was revised from 3,000 to 1,500 this has revised our approach. Converting feeders to 22kV cannot be justified for feeders supplying only 1,500 customers and carrying total load under 5MVA. The system planning studies have also identified that Karaka subtransmission lines N-1 firm capacity, the Karaka substation power transformers and 11kV switchboard will progressively exceed their ratings as the Glenbrook Beach, Clarks Beach, Karaka North and Kingseat area developments approach completion regardless of whether the feeders are operating at 11kV or 22kV. Therefore, the existing Karaka substation and distribution feeders can support the growth in the north western areas in the short to medium term beyond which upgrades at subtransmission and substation levels will be required.

For the later stages in the medium to long term four options of supply were considered.

Option 1 – Extend and increase Karaka Zone Substation capacity

This option would consist of the following upgrades at the existing Karaka Zone Substation to raise firm capacity above 20MVA for N-1 events:

- Increase the transformer capacity at Karaka by replacing the transformers with nonstandard 33/22kV 20/40MVA transformer, with an estimated cost of $2 million;
- Increase the subtransmission capacity of both Glenbrook Karaka 33kV lines 13km each, at an estimated cost of $9.5 million;
- Extend the control room at the substation to make provision for a new 22kV switchboard and related equipment, with an estimated cost in the order of $3 million;
- Convert to 22kV operation, five feeders of average length 12km to each development, with an estimated cost in the order of $25 million; and
- Convert to 22kV operation one feeder of 15km length out of Waiuku substation, with an estimated cost in the order of $5 million.

This option is at an estimated cost in the order of $44.5 million and would introduce a number of HILP risks, namely the common mode failure of the 22kV switchboard, the vulnerability due to a fire or explosion in the outdoor yard, the risk of targeted vandalism and the risk of an incident when plant is out of service for maintenance. There is introduction of nonstandard power transformers and less flexibility of supply options. Any new feeders required for future growth will have to be at least 12km long and cost more to maintain over its lifetime with higher losses ultimately recovered from the customers. $9.5 million of investment (for the existing subtransmission line upgrade) is dependent on whether the load exceeds 12MVA to then require N-1 security

This option does however provide a number of advantages, specifically:

- Converting feeders to 22kV distribution voltage will address the capacity and voltage constraints for 20 years at 45% to 60% of the cost of a substation beyond which time substations upgrades or new feeders would be required; and
- Existing land and line routes are utilized. It is not necessary to buy new land or find new line routes.

Option 2 – Development of smaller substations at Kingseat and Glenbrook Beach

This option would consist of the following upgrades at the proposed new substations located at Kingseat and Glenbrook Beach to supply load in their locality and reduce the load at Karaka below its firm capacity of 20MVA:

Kingseat substation

- Purchase land for the substation development with an estimated cost of $2 million;
- Secure 33kV line routes for the Kingseat Substation at an estimated cost of $1 million; and
- Build the new 33kV substation and feeder works with an estimated cost of $14.7 million;

Glenbrook Beach substation

- Purchase land for the substation development with an estimated cost of $2 million;
- Secure 33kV line routes for the Glenbrook Beach Substation at an estimated cost of $1.5 million; and
- Build the new 33kV substation, install sub transmission circuits and feeder works with an estimated cost of $20.5 million.

This option is at an estimated cost in the order of $41.7 million although there is added complexity given the need for new 33kV subtransmission corridors and new distribution feeder configurations. Note costs are based on new components, this may be reduced if the Ex-Maioro transformers are able to be re-furbished and reused and $8.2 million of investment (for the second subtransmission line and distribution feeders) is dependent on whether the load exceeds 12MVA to then require N-1 security.

It does however provide a number of advantages, specifically:

- Closer to the load centres of Glenbrook Beach, Clarks Beach, Karaka North and Kingseat areas and the future northern development areas. No feeder conversion required;
- Releasing of capacity at Karaka and Waiuku substations to accommodate more localised growth; Karaka substation upgrades can be deferred;
- Diversity of supply and provision of interconnection into Karaka, Pukekohe North and Waiuku;
- Improved resilience against HILP events (subtransmission and distribution);
- Shorter feeders (average 4km) are lower cost to maintain over the lifetime of the feeder with lower losses. It is easier to acquire line routes for shorter feeders direct to load centres with the new developments areas having more road route options, rather than crowding corridors of rural roads that lie between existing substations and the new load centres and often there is only one road option having to then explore cross country line routes through private land;
- Customer numbers per feeder can be managed and back-feeding is easier to achieve during fault conditions; and
- New substations closer to the load centres is a more open ended solution and has the option of servicing load growth for at least a further 20 years compared to option 1, if appropriate associated upgrades are made, as required.

Option 3 – Increase Karaka Zone Substation capacity and establish Glenbrook Substation

This option would consist of the following upgrades at the existing Karaka Zone Substation to raise firm capacity above 20MVA for N-1 events:

- Increase the transformer capacity at Karaka by replacing the transformers with nonstandard 33/22kV 20/40MVA transformer, with an estimated cost of $2 million;
- Without extending the control room at the substation existing Te Hihi feeder is upgraded to greater capacity cable and connected ring main units outside the substation to operate as two feeders, one existing overhead and a second 10km feeder cable to Kingseat development via autotransformer, with an estimated cost in the order of $4 million;
- Backfeed is provided by the existing Pakington feeder is upgraded to greater capacity cable and connected ring main units outside the substation to operate as two feeders, one existing overhead and a second 10km feeder cable to Kingseat development via autotransformer, with an estimated cost in the order of $4 million[28]; and
- The load at Glenbrook Beach and Clarks Beach will be addressed by establishing the Glenbrook Beach substation, with an estimated cost of $24 million (including the feeders works).

This option is at an estimated cost in the order of $34 million, the HILP risk exposure is reduced as there now will be two sources of supply. There is added complexity given the need for new 33kV subtransmission corridors and new distribution feeder configurations. Note costs are based on new components at Glenbrook substation, this may be reduced if the Ex-Maioro transformers are able to be re-furbished and reused and $6 million (for the second subtransmission line) of investment is dependent on whether the load exceeds 12MVA to then require N-1 security.

[28] Note: There will be 5 ring main units and 3 auto transformers outside Karaka substation to avoid replacing the switchboard before its end of life.

It does however provide a number of advantages, specifically:

- Closer to the load centres of Glenbrook Beach, Clarks Beach but same distances from Karaka North and Kingseat areas and the future northern development areas. New feeders will be built at 22kV with minimal additional costs rather than converting existing feeders;
- Offloading Glenbrook Beach, Clarks Beach from Karaka and Waiuku substations to accommodate more localised growth; Karaka substation sub transmission lines upgrades can be deferred;
- Diversity of supply and provision of interconnection into Pukekohe North and Waiuku; and
- Improved resilience against HILP events (subtransmission and distribution).

This is a hybrid solution using one new substation and one existing substation, there is significant deferment of costs by delaying one substation beyond the planning period. The Glenbrook and Clarks Beach areas will have the advantages of shorter feeders but not the longer new feeders out of Karaka, however being largely in underground construction will significantly improve their reliability and this solution also overall addresses the customer number targets. Longer term either a new second substation will have to be built at Kingseat or Karaka substation will have to rebuilt.

Option 4 – Establish Kingseat Substation

This option would consist of the following upgrades at the proposed new substations located at Kingseat to supply Kingseat, Glenbrook and Clarks Beach developments and reduce the load at Karaka below its firm capacity of 20MVA:

Kingseat substation

- Purchase land for the substation development with an estimated cost of $2 million;
- Secure 33kV line routes for the Kingseat Substation at an estimated cost of $1 million;
- Build the new 33kV substation and feeder works with an estimated cost of $14.7 million;
- The load at Glenbrook Beach and Clarks Beach will be addressed by converting Waiau Pa feeder, with an estimated cost of $8 million (including second submarine cable rated for 33kV);
- Backfeed is provided by installing a new 12km cable feeder to Glenbrook Beach, with an estimated cost of $5 million; and
- The Glenbrook Karaka North line supplying the Kingseat substation will be assessed for short term overload ratings and could need capacity upgrades, with an estimated cost of $9.5 million (currently considered to be outside this planning period).

This option is at an estimated cost in the order of $40.2 million, the HILP risk exposure is increased as there is now one source of supply. The 33kV subtransmission supply is by installing short Tee connections to the existing Glenbrook Karaka North line. Note costs are based on new components, this may be reduced if the Ex-Maioro transformers are able to be re-furbished and reused and $11 million (for the existing subtransmission line upgrades and distribution feeders) of investment is dependent on whether the load exceeds 12MVA to then require N-1 security and the subtransmission line short term overload ratings.

It does however provide a number of advantages, specifically:

- Closer to the biggest load centre of Kingseat but same distances from Glenbrook Beach, Clarks Beach and Karaka North areas and the future northern development areas. New feeders will be built at 22kV with minimal additional costs, however one existing feeder will be converted unless alternate route is available and that will reduce the investment;
- Offloading Kingseat from Karaka substation to accommodate more localised growth; Karaka substation sub switchboard and transformer upgrades can be deferred; and
- Diversity of supply and provision of interconnection into Pukekohe North and Waiuku;

This is a hybrid solution using one new substation and one feeder conversion there is significant deferment of costs by delaying the most expensive substation beyond the planning period. The Kingseat and neighbouring areas will have the advantages of shorter feeders but not the longer feeders to Glenbrook and Clarks Beach, however the second feeder being largely in underground construction will significantly improve their reliability and this solution also overall addresses the customer number targets. Longer term a second substation will have to be built at Glenbrook Beach and Karaka substation can be decommissioned at end of life or retained as a switching station.

On present projections the Kingseat developments is progressing much faster than the developments at Glenbrook and Clarks Beaches. The high level of uncertainty around the uptake of the developments means that the solution is not well formed at this stage. It will be a combination of substation and feeder upgrades staged to best address the growth. Further investigations will be undertaken over the next few years as the housing developments take place and we will optimise the network configuration including the issue of establishing new local area substations as load data and development rates become available.

As these constraints are being caused by land development in locations some distance from the existing zone substations and high capacity network areas, the substantial costs relative to the number of customers and expected revenue means that a detailed economic analysis has to be completed for any solutions. A full business case would be required, including analysis of all viable alternatives, and it is expected that the land developers will be required to make significant contributions to funding this infrastructure.

Proposed investment

Our proposed investment is to build two new 33/11kV 2x10/20MVA Kingseat Area and Glenbrook Beach Area substations to supply the Kingseat, Clarks Beach and Glenbrook Beach housing developments' anticipated load south of the Auckland City Rural Urban boundary. These new substations would supply the developments, reducing the reliance on Karaka substation and existing rural distribution feeders not suited to supply high density residential load areas without significant upgrades, and will provide supply diversity.

Our network development plan allows for the proposed new 33kV Glenbrook Beach Area substation to be supplied directly from the Glenbrook GXP and the proposed new 33kV Kingseat Area substation to be supplied via a diversion from Glenbrook Karaka North line. The development will be staged with a Kingseat substation established first subsequently followed by Glenbrook Beach substation with one single 33kV line built initially and the second line added when the load reaches 12MVA. The proposed investment represents the optimum long term solution when considering factors including value, security of supply and customer experience. The new substation establishment solutions will impact the future plan for Karaka substation whether to extend or decommission it and the timing of the same.

Refer to Figure 6-25 for the proposed subtransmission single line diagram for the proposed new Kingseat and Glenbrook Beach area substation and 33kV supply from the Glenbrook GXP.

Our development plan for proposed 33kV Kingseat substation is to:

- Purchase land for the substation development with an estimated cost of $2 million in 2019/20;
- Secure 33kV line routes for the Kingseat Substation at an estimated cost of $1 million in 2021/22;
- Establish a new Kingseat area substation at a cost of $14.7 million in 2022/23 to 2027/28;
- Convert Waiau Pa feeder to defer the establishment of Glenbrook substation at a cost of $8 million in 2027/28; and
- Install a new feeder from Kingseat to Glenbrook Beach to provide backfeed at a cost of $5 million in 2027/28.

Our development plan for proposed 33kV Glenbrook Beach substation is to:

- Purchase land for the substation development with an estimated cost of $2 million in 2020/21;
- Secure 33kV line routes for the Glenbrook Beach Substation at an estimated cost of $1.5 million in 2021/22; and
- Establish a new Glenbrook Beach area substation at a cost of $20.5 million in 2029/30 with a single subtransmission line supply.

The following table summarises the proposed North Western Area substation development plan.

Description	Scope	Timing	Estimated Costs ($'000)
Kingseat Area Substation land acquisition	Procure land for the establishment of Kingseat Area Substation	2019/20	2,000
Glenbrook Beach Area Substation land acquisition	Procure land for the establishment of Glenbrook Beach Area Substation	2020/21	2,000
Kingseat Area Substation 33kV line routes	Secure 33kV line routes to supply Kingseat Area Substation	2021/22	1,000
Glenbrook Beach Area Substation 33kV line routes	Secure 33kV line routes to supply Glenbrook Beach Area Substation	2021/22	1,500

Description	Scope	Timing	Estimated Costs ($'000)
Kingseat Area Substation establishment	Build a new Kingseat Area Substation with two 33/11kV 20MVA transformers and 22kV switchboard	2022/23-2027/28	14,700
Glenbrook Beach Area supply	Convert Waiau Pa feeder to 22kV via an autotransformer out of Kingseat substation switchboard	2027/28	8,000
Glenbrook Beach Area supply (Backfeed)	Install a new feeder to 22kV via an autotransformer out of Kingseat substation switchboard	2027/28	5,000
Glenbrook Beach Area Substation establishment	Build a new Glenbrook Beach Area Substation with two 33/11kV 20MVA transformers and 22kV switchboard	2029/30	20,500

Table 6-20 Karaka substation development plan

Karaka Zone Substation Feeder Investment

Figure 6-20 shows the demand forecast for Karaka substation feeders.

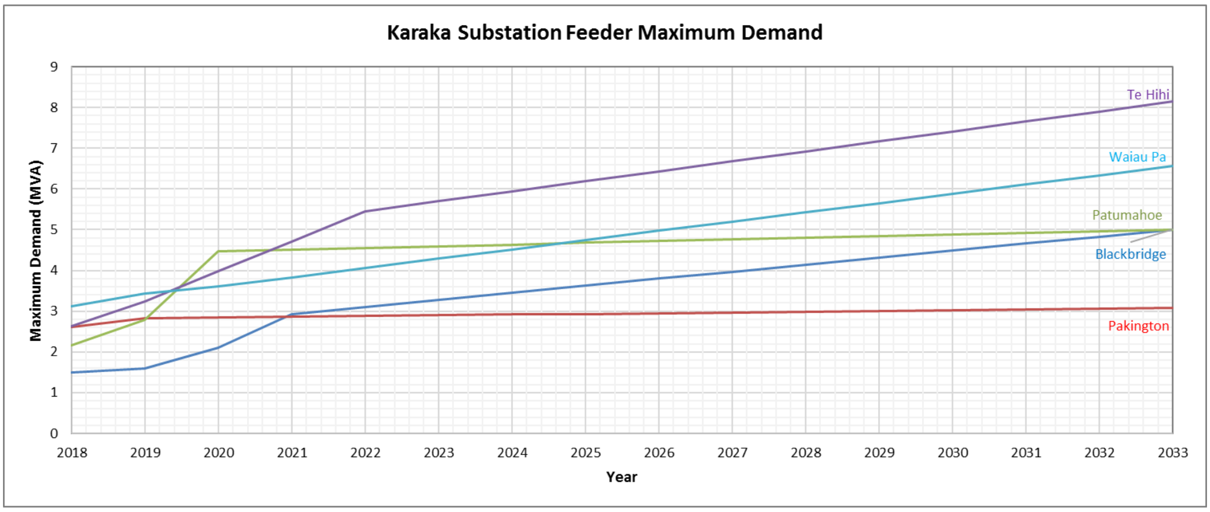


Figure 6-20 Feeder Demand Forecast at Karaka Zone Substation

Our development plan for Karaka Zone Substation Feeders is to:

- Split Patumahoe feeder by upgrading the initial section of cable, 1km of overhead conductor and autotransformer and install 1km of new overhead line along Batty Road. This project to provide backfeed to the Paerata Rise development, and defer the proposed new Pukekohe North substation, will be completed in 2019/20, at an estimated cost of $540,000;
- Install a voltage regulator and upgrade autotransformer on Blackbridge feeder in 2020/21 to increase supply capacity to Karaka North development in the short term to medium term, at an estimated cost of $400,000;
- Install a voltage regulator at switch 47 along the Te Hihi feeder in 2021/22, with an estimated cost of $350,000. This investment is to accommodate the identified load growth on the feeder due to development around Kingseat in the short to medium term;
- Convert the section of Patumahoe feeder supplying the eastern limb to 22kV in 2021/22. This project is to improve the capacity of Patumahoe feeder to supply the Paerata Rise

development, as Anchor Factory feeder is forecast to have customer number and capacity constraints, at an estimated cost of $2.2 million;

- Convert Blackbridge feeder to 22kV operation, in 2026/27, with an estimated cost of $5 million. This investment will provide more system flexibility by enabling us to backfeed load from large subdivision developments in the Opaheke and Pukekohe north areas; and
- Replace Karaka 11kV switchboard in 2028/29 to provide the required number of feeder supplies to meet the target of 1,500 customers per feeder, at an estimated cost of $1.2 million.

We considered the following alternative development options:

- Installing new feeders from Karaka or Waiuku into the new load centres to reduce existing loading, however the geographic location relative to the substation, combined with the aged existing 11kV network gives overall benefit to adopting smaller substations to the load centres;
- Localised energy storage or distributed generation to reduce the peak demand, however this option is costly for the level of utilisation and required capacity to address this constraint. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of the investment planning process; and
- 22kV conversion of existing assets will defer the substation investments for 20 years but to work towards the security target of 1,500 customers per feeder, more 22kV feeders will be required at which point Karaka substation transformers and switchboard will need to be upgraded exposing the whole north western area to HILP event risks.

Summary of Karaka Development Plan

Description	Scope	Timing	Estimated Costs ($'000)
Patumahoe feeder split	Split Patumahoe feeder front section cable, install ring main unit, build 1km of new line section and upgrade 1km of Grasshopper to Cricket	2019/20	540
Blackbridge feeder voltage support upgrade	Install voltage regulator and upgrade autotransformer on Blackbridge feeder	2020/21	400
Te Hihi feeder	Install voltage regulator at switch 47	2021/22	350
Patumahoe Feeder upgrade	Convert Patumahoe feeder section supplying Anchor Factory feeder to 22kV	2021/22	2,200
Blackbridge Feeder upgrade	Complete 22kV conversion of Blackbridge feeder and reconductor 600m feeder section	2026/27	5,000
Replace 11kV switchboard at Karaka substation	Replace 11kV switchboard at Karaka to provide required number of feeders	2028/29	1,200

Table 6-21 Summary of Karaka Development Plan

6.5.5 Waiuku Zone Substation

The 33/11kV Waiuku zone substation is supplied by two 33kV subtransmission lines from Glenbrook GXP. Waiuku Zone Substation supplies 670 distribution substations in the urban areas of Waiuku, Racecourse Road and rural areas of Glenbrook, Te Toro and Manukau Heads. The load is a mix of residential and commercial. Waiuku is classed as a large zone substation (C4), however it is not presently compliant with our security criteria due to the rating of the 11kV switchboard (refer to 6.1.2).

The Waiuku load is has a winter peak. The forecast peak demand for Waiuku Zone Substation and the distribution feeders from the substation is shown in Table 6-21.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Glenbrook	1.5	1.5	1.8	2.2	2.3	2.5	2.7	2.8	3.0	3.1	3.3	3.4	3.6	3.8	3.9	4.1	11.7%
Manukau Heads	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.7	1.1%
Racecourse	3.1	3.1	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.5	3.6	3.6	3.7	3.7	1.3%
Te Toro	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	1.0%
Waiuku South	1.9	1.9	1.9	2.0	2.0	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.0%
Waiuku Town	3.6	4.1	4.3	4.3	4.4	4.5	4.5	4.6	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.2	3.0%
Waiuku West	4.2	4.3	4.4	4.5	4.6	4.6	4.7	4.8	4.9	5.0	5.1	5.1	5.2	5.3	5.4	5.5	2.0%
Zone Substation	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Waiuku	17.4	18.1	18.8	19.4	19.8	20.2	20.6	21.0	21.5	21.9	22.3	22.7	23.1	23.5	23.9	24.3	2.7%
Waiuku Town Feeders	10.9	11.5	11.8	12.0	12.2	12.4	12.6	12.8	13.0	13.2	13.4	13.6	13.8	14.0	14.2	14.4	limit 13.7

Table 6-22 Winter Maximum Demand at Waiuku Substation and Feeders

Waiuku Zone Substation Investment

The Waiuku Zone Substation demand forecast is shown in Figure 6-21.

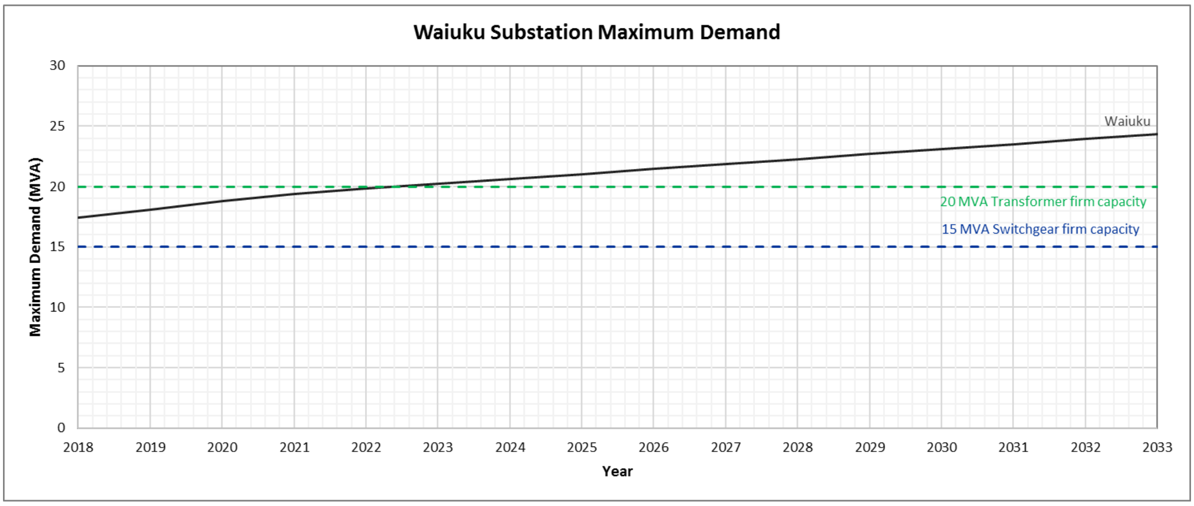


Figure 6-21 Waiuku Zone Substation Demand Forecast

Two 33/11kV, 10/20MVA transformers supply the load at Waiuku providing N-1 capacity of 20MVA. The present switchgear reduces the firm capacity to 15MVA. The Waiuku maximum winter demand currently exceeds the Waiuku 11kV switchgear N-1 capacity and is managed with operational measures and will exceed the transformer N-1 capacity by 2023.

The new Counties Power planning guide suggests the use of short term cyclic ratings in excess of nominal rating to defer the need for investment. If this can be done at Waiuku, this will defer the need for transformer reinforcement at Waiuku beyond 2033. The 3MVA exceedance above the rating beyond 2033 can be readily transferred to Karaka, Pukekohe substations during peak load periods. If the proposed Glenbrook Beach substation is established, the peak will reduce by 2MVA further deferring the transformer upgrade.

The Waiuku Zone Substation building is 65 years old and has been identified as not meeting the current building seismic standard and therefore requires strengthening or rebuild.

The Waiuku substation rebuild project commenced in 2018/19 with the preliminary design, consenting and procurement activities as well as enabling works such as cabling and removal of overhead lines crossing the site. Construction of the new switchroom, electrical fitout and commissioning will continue into 2019.

Proposed investment

Our development plan for Waiuku zone substation is to redevelop at the existing site.

- Replace the 11kV switchboard with a new 22kV rated switchboard in a new building. Replace the last remaining 33kV oil circuit breaker supplying Maioro substation and replace the older 33/11kV 10/20MVA transformer with a refurbished ex-Tuakau unit in 2019/20 at an estimated cost of $3.1 million (total budget of $5.7 million including previously committed expenditure). This aligns with power transformer midlife refurbishment and zone substation switchgear renewal programme which is detailed in Section 5.

Waiuku Zone Substation Feeder Investment

Figure 6-21 shows the demand forecast for Waiuku Substation feeders.

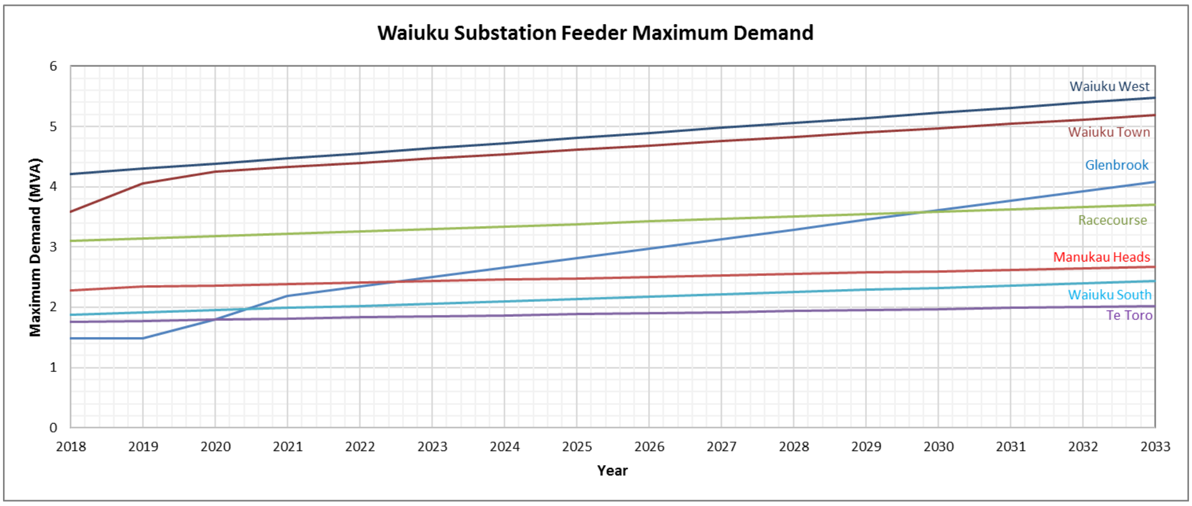


Figure 6-22 Feeder Demand Forecast at Waiuku Substation

Our development plan for Waiuku Substation Feeders is to:

- Replace ABS261 with a recloser and recloser 905 with an automated switch on Manukau Heads feeder to improve network performance in 2019/20 at an estimated cost of $70,000;

- Upgrade a total of 3.6km of Te Toro and Manukau Heads feeders, and install a second voltage regulator on Te Toro feeder in 2021/22 to increase backfeed capacity on the front sections of the two feeders, with an estimated cost of $1.04 million; Further investigations will be undertaken to develop the optimal solution;
- Rebuild the tie section of Waiuku Town and Te Toro feeders in 2021/22 to increase backfeed capacity to the Waiuku Town feeder, with an estimated cost of $500,000; and
- Install two new urban feeders from Waiuku switchboard spare circuit breakers to offload Waiuku Town, Waiuku West and Racecourse Road urban feeders in 2022/23, at an estimated cost of $3.5 million. The existing urban feeders are approaching the customer number targets and currently have capacity constraints when providing backfeed to adjacent feeders.

We expect significant growth from the Glenbrook Beach subdivision development. It has been assumed to incur demand of approximately 800 lots over the next 10 years, and another 250 lots over the remaining planning period.

We considered the following alternative development options:

- Addressing capacity and voltage constraints on Glenbrook feeder using network configuration changes and voltage regulators, is effective only as a short term measure. The medium to long term solution would be to establish a smaller substation closer to the load centre rather than 22kV conversion given the length of the feeders and distance from the load centres; and

- Localised energy storage or distributed generation in strategic locations to assist with capacity (peak lopping) and improve voltage support, but this is not currently cost effective. Counties Power is trialling new technology options to understand the value they provide as well as actively following international developments in new technology. Should the cost of new technology continue to reduce, these options may become viable alternatives and will be considered as part of the investment planning process.

Summary of Waiuku Development Plan

Description	Scope	Timing	Estimated Costs ($'000)
Redevelop existing substation at Waiuku	Rebuild Waiuku zone substation at existing site in two stages	2019/20	3,100
Improve Manuka Heads feeder network performance	Replace ABS261 and recloser 905 with a recloser and automated switch	2019/20	70
Te Toro and Manukau Heads feeder capacity upgrade	Upgrade a total of 3.6km of Te Toro and Manukau Heads feeders and install second voltage regulator on Te Toro feeder.	2021/22	1,040
Waiuku Town and Te Toro feeder tie section rebuild	Rebuild the tie section of Waiuku Town and Te Toro feeders along Kitchener Road	2021/22	500
Two new urban feeders	Install two new 3km underground feeders	2022/23	3,500

Table 6-23 Summary of Waiuku Development Plan

6.5.6 Maioro Zone Substation

The Maioro 33/11kV Zone Substation is supplied by one 33kV circuit from Waiuku Zone Substation 33kV bus, and ultimately from the Glenbrook GXP. Maioro Zone Substation supplies 136 distribution substations in the rural area of Otaua, with a mix of residential and industrial load. Most of the demand on this substation is used by a major consumer, NZ Steel, at their iron sands mine. Maioro is classed as a small zone substation (C3) and is not compliant with our security criteria (refer to 6.1.2) for maintaining maximum demand for both first and second outages. We have a special arrangement with the major customer supplied from this substation for the reduced security on the line, however a transformer outage causes a capacity constraint.

Table 6-24 shows the winter maximum demand for Maioro substation and the distribution feeders from the substation.

11kV Feeders	Max. Dmd (MVA)	Projected Maximum Demand (MVA): Winter Peak															Avg. Annual Increase %
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
Otaua	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0.5%
NZS Mine site & Pump Station 1	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	0.0%
Zone Substation	**Max. Dmd (MVA)**	**Projected Maximum Demand (MVA): Winter Peak**															**Avg. Annual Increase %**
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	
Maioro	9.7	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	0.1%

Table 6-24 Winter Maximum Demand at Maioro Substation and Feeders

We do not anticipate any significant load growth in the area supplied from Maioro over the next ten years. NZ Steel has indicated that increased demand will be required at the mine site in the short term of approximately 650kVA. As such, only minor increases have been allowed for in the demand forecasts and an increase of this magnitude will not lead to any new constraints on the supply assets.

As Maioro is predominantly used for the supply to NZ Steel, and the Otaua feeder can be fully backfed from Waiuku (following upgrades to address capacity and voltage constraints), the future of the NZ Steel site brings uncertainty into future investment decisions. As such any asset replacement will only be undertaken once agreed with NZ Steel through appropriate commercial arrangements, and the nature of work will be done to minimise stranded asset risk should NZ Steel cease their operation. A condition based refurbishment of the 33kV subtransmission line from Waiuku to Maioro will need to be undertaken if the line remains in service in the later part of the planning period as part of an asset renewal project detailed in section 5 Renewal and Maintenance.

Maioro Zone Substation Investment

The Maioro Zone Substation demand forecast is shown in Figure 6-23.

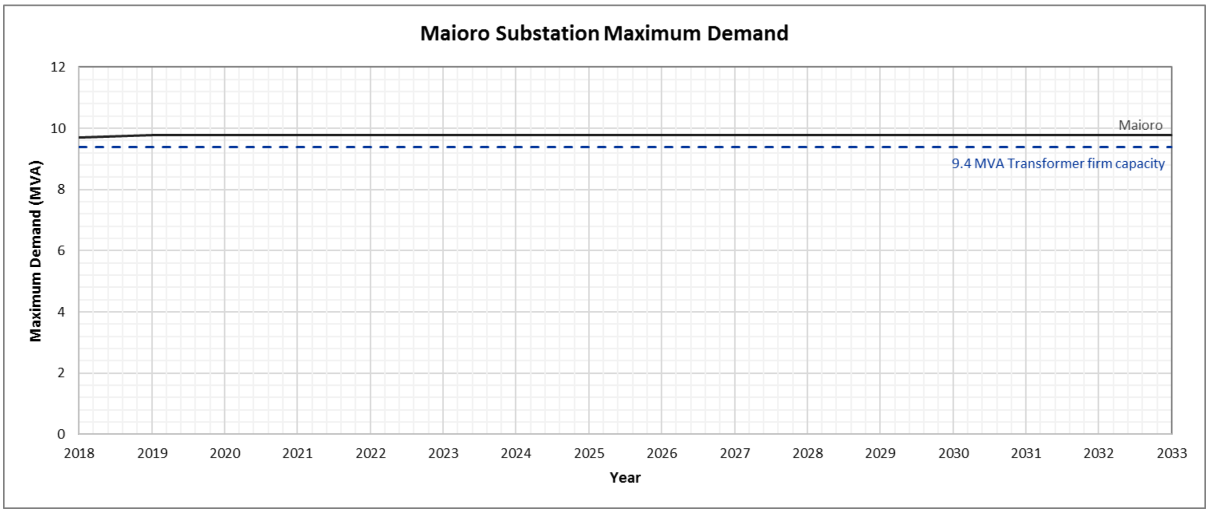


Figure 6-23 Maioro Zone Substation Demand Forecast

Two 33/11kV, 7.5MVA transformers supply the load at Maioro, providing an N-1 capacity of 7.5MVA (9.4MVA allowing for 25% short duration overload). The winter maximum demand already exceeds the firm capacity of the transformers.

The only material project in our development plan for Maioro Zone Substation is to replace the 11kV switchboard due to age and condition, which is detailed in Section 5.

Additionally, should the major customer require a higher level of firm capacity, closer to their demand of 10MVA compared with the existing firm capacity of 9.4MVA, we could relocate existing transformers to Maioro, from Karaka substation as part of the renewal and maintenance plan for power transformers, which is detailed in Section 5.

We considered the following alternative development options:

- Replace the existing Maioro transformers and switchboard with new transformers and switchboard. This option presents higher risk due to asset stranding, and allows full utilisation of assets recovered from other sites which are not fully depreciated; and
- Installing storage or distributed generation to manage peak demand in N-1 situations where there is a transformer capacity shortfall, however this is not presently economic compared with relocating existing plant and does not address age and condition risks.

Maioro Zone Substation Feeder Investment

Figure 6-24 shows the demand forecast of Maioro Substation feeders.

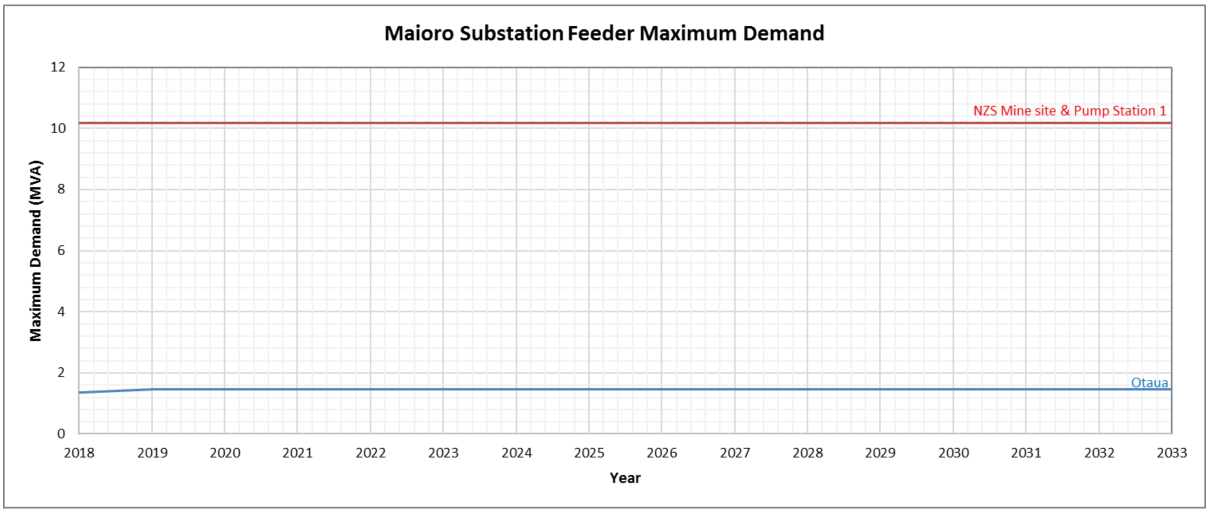


Figure 6-24 Feeder Demand Forecast at Maioro Zone Substation

Our development plan for Maioro Substation Feeders is to install a voltage regulator on Otaua feeder to increase backfeed capacity to Waiuku South feeder in 2021/22 at an estimated cost of $350,000.

Summary of Maioro Development Plan

Description	Scope	Timing	Estimated Costs ($'000)
Otaua feeder voltage support upgrade (Hoods Landing Road)	Install a voltage regulator on Otaua feeder	2021/22	350

Table 6-25 Summary of Maioro Development Plan

6.5.7 33kV Storey Road Point of Supply

Storey Road Point of Supply is supplied off the 33kV Maioro-Waiuku line and supplies No. 2 pump station on the New Zealand Steel slurry pipeline. We have no assets on this site apart from a 33kV disconnector. We do not expect any load growth from this point of supply and consider the existing arrangement adequate for the foreseeable future.

Figure 6-25 shows the single line schematic for the Future Western region subtransmission network supplied from the Glenbrook grid exit point.

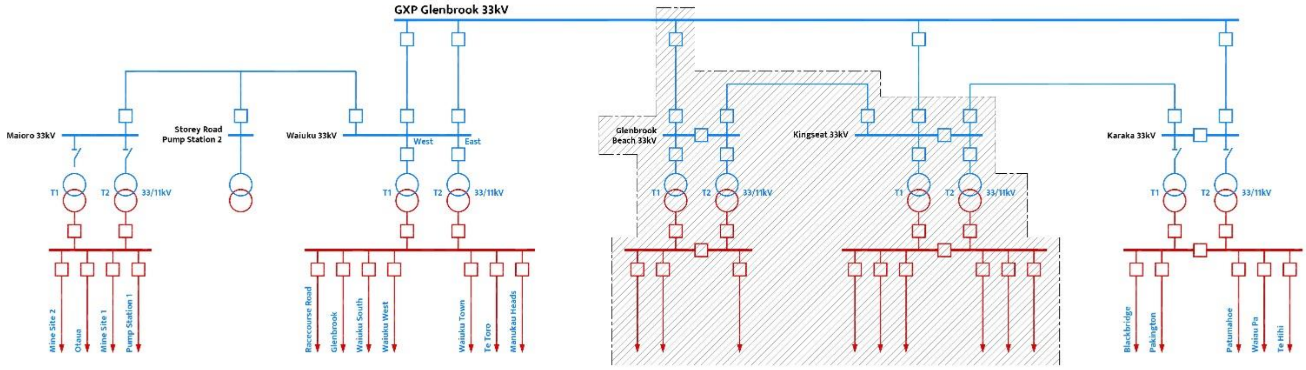


Figure 6-25 Single Line Schematic of the Future Western Region subtransmission network

6.6 Summary of capital expenditure

Table 6-26 below summarises the projected costs for subtransmission and distribution system development. Significant planning expenditure for the next ten years include:

Over the next five years,

- Rebuild the Waiuku substation to replace the existing substation due to capacity constraints, age and condition;
- Install a new 22kV distribution feeder from Tuakau substation to supply Pokeno industrial area;
- Building a new 110kV Pokeno area substation;
- Install earthing transformers at Opaheke and Pukekohe substations;
- Building a new 110kV Drury South substation;
- Install 22kV feeders within Drury South Industrial Estate and for interconnection to the Opaheke West area;
- Building a new 110kV Bombay area substation (including decommissioning the existing 33/11kV Ramarama and Mangatawhiri zone substations);
- Feeder conductor upgrades and voltage regulator installations to address capacity and voltage performance constraints driven by load growth;
- Install a new 22kV distribution feeder and replace 22kV switchboard at Opaheke substation to increase backfeed capacity and reduce customer numbers on feeders; and
- Building a new 33kV Kingseat area substation.

Over the following five years,

- Feeder conductor upgrades and voltage regulator installations to address capacity and voltage performance constraints driven by load growth;
- Build a new 110kV Pukekohe North area substation and new distribution feeders to supply Paerata Rise and Karaka North;
- Convert Blackbridge feeder to 22kV operation;

- Split Kaiaua feeder for improved security, reduced customer numbers and backfeed flexibility;
- Build a new 33kV Glenbrook Beach area substation and new distribution feeders to supply Clarks Beach and Glenbrook Beach;
- Increasing transformer capacities at Opaheke and Tuakau substations; and
- Replace switchboard at Karaka substation.

All work programmes, financial profiles and actions described throughout this plan indicate the company's intentions based on the information presently available to it. They may be amended in response to new information. They are also subject to detailed study and verification in accordance with sound engineering practice and, in respect of financial expenditure, established processes for management and Board approval.

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Eastern Region										
Drury South Business Park	1,500	19,000	-	2,000	-	-	-	-	-	-
Eastern Supply Project (Ramarama & Mangatawhiri)	35	3,000	12,780	3,000	6,330	-	1,000	-	150	1,800
Opaheke Substation Supply Area	870	-	400	2,000	4,630	-	-	-	-	-
Pokeno Industrial Area	14,260	-	590	-	-	-	-	-	-	-
Pukekohe North Substation Supply Area	2,300	1,500	-	-	2,800	-	7,400	2,600	-	7,400
Pukekohe Substation Supply Area	1,045	50	-	130	2,350	280	-	-	-	-
Tuakau Substation Supply Area	995	-	400	-	-	-	-	-	-	-
Western Region										
Glenbrook Substation Supply Area	-	2,000	1,500	-	-	-	-	-	-	-
Karaka Substation Supply Area	540	400	2,950	-	-	-	-	5,000	-	1,200
Kingseat Substation Supply Area	2,000	-	1,000	10,000	3,200	-	-	-	14,500	-
Maioro Substation Supply Area	-	-	350	-	-	-	-	-	-	-
Waiuku Substation Supply Area	3,470	-	1,540	3,500	-	-	-	-	-	-
Network Wide										
Network Wide - System Automation	600	1,536	-	-	-	-	-	-	-	-
Quality of Supply - Voltage	350	350	350	350	350	350	350	350	350	350
Total	**27,965**	**27,836**	**21,860**	**20,980**	**19,660**	**630**	**8,750**	**7,950**	**15,000**	**10,750**

Table 6-26 Projected Expenditure for Subtransmission and Distribution System Development

Note: Forecasts are stated in real (constant) prices

7 Non-network Investment Plan

In addition to the planned maintenance, renewal and development of network assets detailed in Section 5 and Section 6. We have identified expenditure requirements on Non-Network assets including our Information Technology hardware and software, our tools and equipment, as well as our vehicle fleet.

Information technology upgrades and replacement

The following major systems upgrades have been identified as requiring capital investment in the short to medium term of the plan. Other minor systems are expected to require replacement or upgrade during the planning period, however their cost is not material in terms of the Non-Network Investment Forecast.

Function	System	Year	Estimated Cost ('000s)
ERP Upgrade	Upgrade of the Microsoft NAV Dynamics platform from 2009 to 2017.	2019/20	250
Digital & Mobility Transformation	Application of digital technology across all business functions	2019/20	700
Asset Management	System to manage assets through their lifecycle[29]	2019/20	450
Customer Relationship Management	System to manage and analyse customer interactions and data throughout the customer lifecycle	2019/20	300
Security Initiatives	Network security upgrades	2019/20	100
Routine Replacement			
Core Network Infrastructure	Network Infrastructure such as switches, servers, UPS, etc. to maintain network reliability.	3-5 year replacement cycle	150 per annum
PCs, Laptops and Field Mobile Devices	Replacement of devices to ensure fit for purpose	2-4 year replacement cycle	75 per annum

[29] scoping of the Asset Management application system will consider migration of asset survey and vegetation management records from the Microsoft Dynamics NAV system as part of asset lifecycle record consolidation.

Tools and equipment

Our non-network expenditure forecasts allow for the ongoing replacement of tools and equipment used by our teams. It is also expected that new test and inspection equipment will be purchased in 2019/20 to support the maintenance programme.

Vehicle fleet and machinery

We own our fleet of light and heavy vehicles, as well as field machinery such as excavators and directional drilling machines, along with their transport trailers.

Our expenditure forecasts allow for the replacement of these as required through the planning period, as well as operational expenditure for the ongoing maintenance to ensure safety and reliability.

Expenditure Forecast ($000)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital Expenditure										
Total	6,433	2,626	2,163	1,450	1,499	1,509	1,540	1,590	1,602	1,634

Note: Forecasts are stated in real (constant) prices

8 Expenditure Summary

This section provides a summary of the forecast expenditure from the three investment sections – Renewals and Maintenance, Network Development and Non-Network.

8.1 Capital expenditure summary

8.1.1 Renewal and replacement expenditure

Note: Forecasts are stated in real (constant) prices

Asset Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Subtransmission network	**50**	**50**	**50**	**50**	**50**	**3,500**	**500**	**50**	**50**	**50**
Maioro Line Refurbishment						450	450			
Bombay - Ramarama Tower Line Renewal						3,000				
Other Subtransmission Renewal	50	50	50	50	50	50	50	50	50	50
Zone Substations	**650**	**50**	**350**	**350**	**350**	**400**	**50**	**50**	**50**	**50**
Zone Substation switchgear										
Replace Maioro 11kV Switchboard						350				
Oil Separator Plant	600									
Power Transformer Refurbishment			300	300	300					
Other Zone Substation Renewal	50	50	50	50	50	50	50	50	50	50
Distribution and LV lines	**7,170**	**6,680**	**8,240**	**7,910**	**9,350**	**10,100**	**10,420**	**10,080**	**9,350**	**10,380**
Distribution poles and crossarms										
Overhead Renewals	3,350	3,350	3,300	3,300	3,300	3,290	3,300	3,300	3,300	3,300
Distribution conductor										
Copper Replacement Programme	2,050	910	1,990	2,500	2,460	2,210	2,410	2,600	2,640	3,150
Swan Replacement Programme	900	1,380	2,200	1,390	2,950	3,750	4,050	3,530	2,630	3,230
HV Feeder section replacement	650	390	300	300	300	300	300	300	300	300
Urban LV Replacement	120	550	350	320	240	450	260	250	380	300
Overhead Safety Compliance	100	100	100	100	100	100	100	100	100	100
Distribution and LV cables	**330**	**340**	**350**	**360**	**510**	**520**	**530**	**540**	**550**	**560**
Distribution and LV cables Renewal	150	150	150	150	300	300	300	300	300	300
LV Pillar Renewal	180	190	200	210	210	220	230	240	250	260
Distribution substations and transformers	**750**	**650**	**660**	**750**	**660**	**400**	**450**	**450**	**450**	**450**
Distribution transformers										
Transformer Renewal Programme	750	650	660	750	660	400	450	450	450	450
Distribution switchgear	**2,320**	**1,740**	**1,400**	**1,380**	**1,570**	**960**	**960**	**960**	**960**	**960**
RMU replacement	1,720	1,140	920	960	1,120	480	480	480	480	480
Overhead switchgear replacement	600	600	480	420	450	480	480	480	480	480
Other System Fixed Assets	**1,490**	**1,910**	**100**	**90**	**120**	**380**	**110**	**300**	**90**	**100**
Capacitors and Voltage regulators										
Voltage regulator replacement	360									
Protection										
New AUFLS/Extended Reserves Relays		300								
Protection relays replacement and upgrade	320					240				
SCADA and Communications										
Advanced Distribution Management System (ADMS)		1,500								
RTU Replacement	20	30	20	20	40	30	30	30	10	20
Battery banks	20	30	30	20	30	60	30	20	30	30
Load Control Plant Replacement	300							200		
Network Locks Replacement	420									
Other protection, control and radio communications renewal	50	50	50	50	50	50	50	50	50	50
Subtotal	**12,760**	**11,420**	**11,150**	**10,890**	**12,610**	**16,260**	**13,020**	**12,430**	**11,500**	**12,550**
Capitalised Maintenance	900	900	900	900	900	900	900	900	900	900
Total	**13,660**	**12,320**	**12,050**	**11,790**	**13,510**	**17,160**	**13,920**	**13,330**	**12,400**	**13,450**

8.1.2 Network development expenditure

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Eastern Region										
Drury South Business Park	1,500	19,000	-	2,000	-	-	-	-	-	-
Eastern Supply Project (Ramarama & Mangatawhiri)	35	3,000	12,780	3,000	6,330	-	1,000	-	150	1,800
Opaheke Substation Supply Area	870	-	400	2,000	4,630	-	-	-	-	-
Pokeno Industrial Area	14,260	-	590	-	-	-	-	-	-	-
Pukekohe North Substation Supply Area	2,300	1,500	-	-	2,800	-	7,400	2,600	-	7,400
Pukekohe Substation Supply Area	1,045	50	-	130	2,350	280	-	-	-	-
Tuakau Substation Supply Area	995	-	400	-	-	-	-	-	-	-
Western Region										
Glenbrook Substation Supply Area	-	2,000	1,500	-	-	-	-	-	-	-
Karaka Substation Supply Area	540	400	2,950	-	-	-	-	5,000	-	1,200
Kingseat Substation Supply Area	2,000	-	1,000	10,000	3,200	-	-	-	14,500	-
Maioro Substation Supply Area	-	-	350	-	-	-	-	-	-	-
Waiuku Substation Supply Area	3,470	-	1,540	3,500	-	-	-	-	-	-
Network Wide										
Network Wide - System Automation	600	1,536	-	-	-	-	-	-	-	-
Quality of Supply - Voltage	350	350	350	350	350	350	350	350	350	350
Total	**27,965**	**27,836**	**21,860**	**20,980**	**19,660**	**630**	**8,750**	**7,950**	**15,000**	**10,750**

8.1.3 Customer programme expenditure

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Customer Connections	12,690	13,100	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Asset Relocations	300	300	300	300	300	300	300	300	300	300
Total	12,990	13,400	12,300	12,300	12,300	12,300	12,300	12,300	12,300	12,300
less Customer Contributions of	10,152	10,480	9,600	9,600	9,600	9,600	9,600	9,600	9,600	9,600

8.1.4 Non-network investment

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Non-network assets	6,433	2,574	2,079	1,367	1,385	1,367	1,367	1,385	1,368	1,368

8.1.5 Total capital expenditure by disclosure category

	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Consumer Connections	12,690	13,100	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
System Growth	26,770	25,950	21,510	20,630	12,200	280	8,400	7,600	14,650	10,400
Asset Replacements	13,360	12,020	11,750	11,490	13,210	16,860	13,620	13,030	12,100	13,150
Asset Relocations	300	300	300	300	300	300	300	300	300	300
Reliability, Safety and Environment	1,195	386	350	350	7,460	350	350	350	350	350
Subtotal Network	54,315	51,756	45,910	44,770	45,170	29,790	34,670	33,280	39,400	36,200
WIP carry-over from FY19 to FY20										
WIP carry-over from FY20 to FY21										
Non Network	6,433	2,626	2,163	1,450	1,499	1,509	1,540	1,590	1,602	1,634
TOTAL	60,748	54,382	48,073	46,220	46,669	31,299	36,210	34,870	41,002	37,834

Note: Forecasts are stated in real (constant) prices

8.2 Operating expenditure summary

8.2.1 Network operating expenditure by asset category

Asset Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Subtransmission network	**140**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**	**110**
Subtransmission lines	140	110	110	110	110	110	110	110	110	110
Subtransmission cables	-	-	-	-	-	-	-	-	-	-
Zone Substations	**450**	**460**	**440**	**430**	**430**	**430**	**430**	**430**	**430**	**430**
Zone Substation transformers	150	160	120	120	120	120	120	120	120	120
Zone Substation switchgear	120	120	120	110	110	110	110	110	110	110
Zone Substation other equipment	90	90	110	110	110	110	110	110	110	110
Zone Substation buildings and grounds	90	90	90	90	90	90	90	90	90	90
Distribution and LV lines	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**	**1,040**
Distribution poles and crossarms	950	950	950	950	950	950	950	950	950	950
Distribution conductor	70	70	70	70	70	70	70	70	70	70
Fault indicators and Earthing	20	20	20	20	20	20	20	20	20	20
Distribution and LV cables	**290**	**290**	**290**	**290**	**290**	**290**	**290**	**290**	**290**	**290**
Distribution and LV cables	150	150	150	150	150	150	150	150	150	150
LV Pillars	140	140	140	140	140	140	140	140	140	140
Distribution substations and transformers	**270**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**	**280**
Distribution transformers	270	280	280	280	280	280	280	280	280	280
Distribution switchgear	**370**	**390**	**410**	**410**	**420**	**420**	**430**	**440**	**450**	**460**
Ring main units	120	130	150	150	160	160	170	180	190	200
Overhead switchgear	250	260	260	260	260	260	260	260	260	260
Other System Fixed Assets	**240**	**230**	**240**	**250**	**240**	**240**	**230**	**240**	**260**	**230**
Capacitors and Voltage regulators	20	20	20	20	20	20	20	20	20	20
Protection	120	110	110	130	120	120	110	120	140	110
Load control equipment	40	40	40	40	40	40	40	40	40	40
Battery banks	20	20	30	20	20	20	20	20	20	20
SCADA and Communications	40	40	40	40	40	40	40	40	40	40
Vegetation	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**	**1,350**
Vegetation	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
Public Safety Services	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**
Public Safety Services	150	150	150	150	150	150	150	150	150	150
Faults and Reactive Maintenance	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**	**1,900**
Faults	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Capitalisation	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**	**- 900**
less Capitalised Maintenance	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900	- 900
Total	**5,300**	**5,300**	**5,310**	**5,310**	**5,310**	**5,310**	**5,310**	**5,330**	**5,360**	**5,340**

8.2.2 Network operating expenditure by disclosure category

Asset Category	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Service interruptions and emergencies	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Vegetation management	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
Routine and corrective maintenance and inspection	1,350	1,350	1,360	1,360	1,360	1,360	1,360	1,370	1,370	1,370
Asset replacement and renewal	700	700	700	700	700	700	700	710	740	720
Total	**5,300**	**5,300**	**5,310**	**5,310**	**5,310**	**5,310**	**5,310**	**5,330**	**5,360**	**5,340**

Note: Forecasts are stated in real (constant) prices

9 Evaluation of Performance

9.1 Performance against previous plan

Assessing performance against previous plans is a part of our continual improvement in asset management and overall business performance.

This section provides an assessment of performance against the last complete financial year (FY2018) as well as comparing against the forecast performance of the current financial year at the time of writing.

Our financial year runs from 1 April to 31 March, which aligns with the regulatory year.

Network performance and other service levels are compared against previous targets in Section 3 – Service Levels.

9.1.1 Financial performance FY2018 plan to actual

Capital expenditure FY2018

Disclosure Categories	Target ($000)	Actual ($000)	Variance	Reasons for variance
Consumer Connection	7,700	12,172	58%	Consumer connection expenditure was 58% above forecast. The variance was due to a higher than expected volume of new subdivisions. The forecast was based on the previous year's average and adjusted for known projects.
System Growth	3,790	2,348	(38%)	System growth expenditure was 38% below forecast due to deferral of Drury South land acquisition into FY2020.
Asset Replacement and Renewal	7,460	6,956	(7%)	Asset replacement and renewal expenditure was 7% below forecast due to deferral of some works and delivery efficiencies.
Asset Relocations	300	50	(83%)	Asset relocations expenditure is 83% below forecast due to a lower than expected volume of asset relocation requests. The forecast was based on the expected volumes and adjusted for known major projects.
Other reliability, safety and environment	2,625	1,235	(53%)	Other reliability, safety and environment was 53% below forecast due to the deferral of Tuakau Industrial Power Quality Project.
TOTAL	21,875	22,762	4%	

COUNTIESPOWER

Operational expenditure FY2018

Disclosure Categories	Target ($000)	Actual ($000)	Variance	Reasons for variance
Service interruptions and emergencies	1,700	1,956	15%	Service interruptions and emergency volumes were high resulting in 15% variance to forecast
Routine and corrective maintenance and inspection	2,000	2,198	10%	Routine and corrective maintenance and inspection was 10% above forecast due to budget reallocation.
Asset replacement and renewal	806	667	(17%)	Asset Replacement and Renewal was 17% below forecast due to budget reallocation.
System operations and network support	2,836	2,779	(2%)	Variance not material
Business support	5,617	5,290	(6%)	Variance not material
TOTAL	12,959	12,890	(1%)	

9.1.2 Project performance FY2018 plan to actual

Project	Scope	Project Budget ($000)	Actual completion
Otaua Road rehabilitation	Rehabilitation of hard wood poles and copper conductor	442	FY2018
Racecourse Feeder upgrade	Undergrounding of Sandspit Rd	824	FY2018
Port Waikato Feeder Conversion and River Crossing	22kV conversion	490	FY2018
Church Corner feeder conversion	22kV conversion	809	FY2018
Hull Road and Kidd Road rehabilitation	Rehabilitation works	455	FY2018
Hingaia Feeder Swan conductor replacement	Swan conductor replacement	140	Deferred to align with subdivision undergrounding works in the area
Replacement of 33kV CB at Karaka Substation	Replace 33kV CB at Karaka substation	200	FY2018
Pukekohe substation protection relays replacement	Upgrade Protection at Pukekohe Substation. Replacement of Alstom K series relays	400	FY2018
Cape Hill Swan conductor replacement	Swan conductor replacement	56	FY2018
Tuakau Urban LV replacement (Harrisville Rd & Jellicoe Ave)	Rehabilitation of LV assets along Harrisville and Jellicoe Ave, Tuakau	357	FY2018

Project	Scope	Project Budget ($000)	Actual completion
Pukekohe Urban LV replacement (Lawrie Ave)	Rehabilitation of LV assets along Lawrie Ave, Pukekohe	200	FY2018
Glen Murray Feeder (Chapman Rd) Swan conductor replacement	Reconductoring along Chapman Rd, Glen Murray	890	FY2018
Pukekohe ripple plant converter replacement	Replacement of ripple plant converter at Pukekohe Substation	87	FY2018
Ararimu Feeder (Sinclair Rd) HV section replacement	Replacement of HV conductor along	180	FY2018
Fibre communication link between Opaheke and Bombay	Establishment of fibre communication link between Opaheke and Bombay substations	53	FY2018
Patumahoe Feeder (Mauku Rd) Copper conductor replacement	Reconductoring along Mauku Rd, Patumahoe	430	FY2018
Blackbridge Feeder (Muir Rd) Copper conductor replacement	Reconductoring along Muir Rd, Blackbridge feeder.	125	FY2018
Rebuild Te Toro feeder (Eastern King Street) replacement	Rebuild Te Toro feeder along swimming pool complex on Eastern King Street	180	FY2018
Pokeno Church Feeder upgrade	Installation of second Autotransformer at Mangatawhiri Substation	110	FY2018
Waiau Pa Feeder (Waiau Pa Road) upgrade	Upgrade a section of Waiau Pa feeder along Waiau Pa Road	525	FY2018
Improve supply reliability for residential load on rural feeders	Installation of an additional gas switch at Titi Mauku feeder	50	FY2018
Improve supply reliability on Anchor Factory Feeder	Upgrade feeder automation equipment	85	FY2018
Great South Road Feeder (Quarry Rd and Hillview Rd) feeder upgrade	Reconductoring sections of Great South Road feeder along Quarry Road and Hillview Road	803	$633k completed in FY2018. Carried over for completion in FY2019 due to delay in landowner approval.

9.1.3 Financial performance FY2019 plan to forecast

Forecast capital expenditure FY2019

Disclosure Categories	Target ($000)	Forecast ($000)	Variance	Reasons for variance
Consumer Connection	10,000	11,000	10%	Higher than expected volume of customer initiated work.
System Growth	6,990	6,117	(12%)	Deferral of some projects into FY2020.
Asset Replacement and Renewal	11,295	10,795	(4%)	Variance not material.
Asset Relocations	300[30]	500	66%	Volumes are higher than anticipated, largely driven by high volumes of consumer connections.
Other reliability, safety and environment	1,645	1,506	(8%)	Variance not material.
WIP (Carry In)	2,761	Included above		
Total	32,991	29,917		

Forecast operational expenditure FY2019

Disclosure Categories	Target ($000)	Forecast ($000)	Variance	Reasons for variance
Service interruptions and emergencies	1,900	1,900	-	
Routine and corrective maintenance and inspection	1,350	1,350	-	
Vegetation management	1,100	1,100	-	
Asset replacement and renewal	800	800	-	
System operations and	3,717	3,717	-	

[30] Asset relocation includes customer initiated recoverable work. The initial 2018 AMP included multiple projects in developing areas (e.g. Drury South) with a target of $3,765,000. This was revised to $300,000 in FY2019 as the total offset resulting from recovery on these projects were higher than anticipated.

network support				
Business support	5,582	5,896	5%	Variance not material
Total	14,449	14,763		

9.1.4 Project performance FY2019 plan to forecast

Project	Scope	Project Budget ($000)	Expected completion
Drury South Area Substation site acquisition	Purchase land in the vicinity of southern end of Drury Industrial Park for a new Drury South Area Substation	2000	FY2019
New Pukekawa Trunk Feeder	Rebuild and reroute a section of 22kV line from Tuakau to Pukekawa switching to from a new Pukekawa Trunk feeder.	1000	$310k spent in FY2019. Remainder budgeted for FY2020.
Tuakau industrial power quality	Tuakau industrial power quality	1000	FY2019
River Rd feeder backfeed upgrade (Roberts Rd)	New interconnection point between River Road and Port Waikato	85	FY2019
River Rd feeder backfeed upgrade (Church Corner)	Establish new unground cable section and RMU to provide backfeed to loaded spurline	550	Deferred indefinitely due to change in requirements
Bombay area substation site acquisition	Acquire suitable land and line route for new Bombay area substation	500	Not required. Location on Transpower land subject to commercial agreement
Waiau Pa feeder voltage support upgrade	Upgrade voltage regulator on Waiau Pa feeder	195	FY2020
Glenbrook feeder upgrade	Upgrade 2.4km of overhead section and install a new voltage regulator on Glenbrook feeder	565	FY2020
Waiuku substation rebuild	Rebuild Waiuku Substation, 11kV switchboard replacement and 33kV switchyard rebuild	2000	$1,800k in FY2019, with remaining in FY2020
Voltage support upgrade on Manukau Heads feeders	Install a voltage regulator on Manukau Heads feeder	265	FY2020
Improve supply reliability for Red Hill Feeder	Replace switches 626 and 627 with RMUs with CBs	160	FY2019

Project	Scope	Project Budget ($000)	Expected completion
OH switch renewal	Network automation and OH switch renewal	1400	FY2019
Paparata feeder (Paparimu Rd & Hunua Rd) copper conductor replacement	Replace 1.6km copper overhead conductor.	200	FY2019
Garvie Rd re-conductor & conversion	Replace 1.1km of copper overhead conductor	550	FY2019
Kaiaua Township rehab	Underground 2km of copper conductor	1300	FY2019
Te Hihi Feeder (Ellet Rd) swan conductor replacement	Replace 3.8km of swan conductor	600	FY2019
Park Estate Rd re-conductor	Replace 0.5km of swan conductor	110	FY2019
Waiuku Town UG switchgear replacement	Replace 2 Andelec/Hazemeyer switches, 2 transformers and 1km of cable	500	FY2019
Victoria Ave HV rehabilitation stage 1	Replace 400m of overhead line and re-establish link between Waiuku West and Manukau Heads Feeders	500	FY2019
Mason Ave LV rehabilitation	Replace 360m of overhead LV	280	FY2019
RMU renewal programme	Network automation and RMU renewal	250	FY2019
Whangarata and Hitchen Road Feeders (Front end sections) rebuild	Rebuild front end sections of Whangarata and Hitchen Rd feeders along Whangarata road	990	FY2019
Bombay -Tuakau 110kV line corridor visual mitigation measure	Landscaping and pole relocation as visual mitigation measures for the Bombay - Tuakau 110kV line corridor.	175	FY2019
Port Waikato feeder backfeed capacity upgrade	Upgrade auto-transformer and install voltage regulator on Port Waikato feeder	400	Deferred to FY2020 due to slower rate of load growth.
Hingaia Feeder capacity reinforcement	Additional system growth project to install high voltage cable replacement along Hingaia Road to increase Hingaia feeder backfeed capacity	244	FY2019
Distribution fault anticipation (DFA) devices at	Install DFA devices to enhance monitoring and fault cause	260	FY2019 $180k completed in FY2018.

Project	Scope	Project Budget ($000)	Expected completion
Mangatawhiri, Tuakau, and Pukekawa substations	analysis at Mangatawhiri substation		
Bombay Feeder RMUs replacement	Replacement of RMUs and transformers on Bombay feeder (Raventhorpe site)	570	FY2019 $100k completed in FY2018.
Pokeno Zone Substation	New 110kV GIS substation	3,300	$3,200k in FY2019, remainder of project across FY2020 and FY2021.

10 Appendices

Appendix A – Plan assumptions

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Regulatory Environment	We assume for the purpose of this plan, that existing external regulatory and legislative requirements remain unchanged throughout the planning period. Therefore, the external drivers which influence reliability targets and design, environmental, health and safety standards and industry codes of practice are constant throughout the AMP period.	Regulatory requirements are likely to change, requiring Counties Power to achieve different service standards. This could also impact on the availability of funds for asset management arising from changes to allowance revenue, the extent and impact of future changes cannot be assessed at this point and future plans will allow for any updated regulatory requirements. We note new legislation particularly Safety Legislation, Worksafe, and the industry position on Live Work being key changes we have incorporated. We also note that the Input Methodologies (IMs) will be reviewed in the short term which may have an impact on price and quality standards.	It is unlikely that the regulatory and legislative impost will reduce, thus the most likely impact is an increase in forecast expenditure to meet possible increased standards. Changes to Part 4 Regulations, in particular the allowable WACC, and the treatment of expenditure (CAPEX, OPEX, TOTEX) may lead to alternative investment decisions being made.	High
Transpower Policies (Grid owner perspective)	We assume that Transpower will continue to provide grid supply and undertake projects to meet grid capacity and security requirements, and to meet our development needs and customer service expectations. The costs of maintaining these service levels are passed directly through to customers.	There is no indication of a change of policy or purpose from Transpower. Change is unlikely in the short to medium term. Transpower continues to provide sufficient capacity to meet Counties Power's requirements at the existing GXPs and undertakes the additional investment required to meet additional future demand.	The most likely impact is an increase in Transpower charges to meet possible increased standards.	Low

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Demand Side Management and Peak Control	We assume that the industry will increasingly recognise the importance of demand side management and peak control, resulting in the recognition and support for demand-based charging system by regulators.	Increased power system efficiency and minimisation of investment comes largely by minimising peak demand. We see there will be value in demand side management and peak control such as lower transmission and distribution charges. Reduced levels of long term investment are required leading to a lower overall lower cost to serve. This may also provide new revenue streams and opportunities.	Ineffective peak demand management could impact on future transmission pricing if we cannot minimise the offtake from the grid relative to other users. Demand forecasts may be higher or lower than forecast if peak demand management changes, changing the time and nature of investment.	Medium
Distributed Generation	We assume that no newly sited significant embedded generation is commissioned during the planning period and current generators continue to develop based on the existing regulations. We expect to see a steady increase in small scale DG, but not of a significant scale to affect network demand and growth forecasts in the short to medium term.	This assumption is based on current industry position around large-scale generation development (no large-scale developments, closure of some generation plant). Increasing uptake of micro DG (domestic solar) leads to our view that this will continue over the planning period.	Could require significant unplanned capital investment in the network but would be economically justified by a return on new assets or lower cost alternatives available to address network constraints or alter timing. DG in highly loaded parts of the network, could reduce peak demand, and thus lower future investment requirements. Strong growth in DG in localised areas could also lead to power quality issues.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Emerging Technologies	We assume that there will be no large-scale energy storage systems (batteries) or accelerated uptake of Electric Vehicles (EV) during the planning period. We expect to see a steady increase in small scale energy storage systems and moderate EV uptake as technology continues to improve and costs reduce, but not of a significant scale to affect network demand and growth forecasts in the short to medium term.	This assumption is based on our current understandings around large-scale energy storage systems and EV uptake rate.	Could require significant unplanned capital investment in the network but would be economically justified by a return on new assets or lower cost alternatives available to address network constraints or alter timing. EVs in highly loaded parts of the network, could increase peak demand causing constraints, and thus increase future investment requirements.	Medium
Growth in Demand	Growth in demand at each GXP is predicted to follow a linear growth, with high year on year growth compared to the long-term average. Step change scale growth may occur due to large scale developments.	Recent historical growth shows a linear trend over the long term, but with recent high growth year on year (approx. 2.5% p.a.). Large scale developments could lead to larger than average growth in isolated areas, but not likely to be 'step-change' in scale, unless large industrial and processing loads appear.	Extent of load growth will impact upon demand forecasts and timing of investments (brought forward, or deferred), and the nature of investment made.	Low
Load Profiles	Seasonal load profiles remain consistent with recent historical trends, for both winter-peaking and summer-peaking feeders.	No noticeable change in demand type (predominantly residential peak demand) in each network region over the short term. Changes could arise from higher industrial load as a percentage of total demand (less seasonal) and increases of consumer side products such as heat pumps, operating air conditioning in summer and Solar PV installations.	Seasonal shifts in demand could require planned capacity upgrades to be accelerated or delayed. Increased levels of peak demand management required outside conventional periods.	Low

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Extreme Weather Events	The Counties Power network is exposed to normal climatic variation over the planning period including temperature, wind and rain variances consistent with its experiences since 2000 which have shown an increase in the frequency and severity of weather events.	Forecasts are based on normal climatic variations with an increasing trend of adverse weather, as experienced through the frequency and severity of storm events in recent years.	More extreme weather events could result in higher levels of equipment failure and major repairs and replacements required which are not currently provided for in the expenditure forecasts. It will also have an impact on network performance metrics (SAIDI, SAIFI, Faults per 100kms).	Medium
Demand Diversity/ New Loads	The demand diversity remains generally unchanged throughout the planning period, with a predominantly residential base. We assume that Drury South Business Park adds 10 to 30MVA and Pokeno Industrial area adds 10 to 20MVA of demand increasing the commercial and industrial load. We assume changing load profiles over time, potentially more 'peaky' if effective demand side options are not implemented.	We continue to experience strong residential growth, and an increasing level of commercial and industrial load, but with a relatively constant level of diversity.	New loads will impact on demand growth and change the timing of development projects. Specific new investments may also be required to meet large new loads. More industrial/commercial could change the load profile of the network.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Customer Expectations	Establishment of service levels continue to be through consultation with stakeholders and remain a balance between customer needs, price-quality trade-offs and industry best practice. Performance targets are driven by customer consultation indications. We expect increased performance expectations from our consumers for voltage stability, power quality, and minimising the effect of network operations on different equipment installed in customer premises.	While customers could change their demands for reliability or their willingness to pay for different levels of service; it is our expectation that customers' expectations will increase as the quality of supply improves, and their dependence upon high quality electricity supply increases (particularly industrial customers).	Customers could change their service level demands and willingness to pay resulting in either higher or lower service targets and associated expenditures being required to deliver the revised targets.	Medium
Land Zoning	Zoning for land use purposes remains unchanged (from our current knowledge) during the planning period.	The Auckland Unitary Plan, the Rural-Urban Boundaries, and the Waikato District Plan provide clear direction of which areas growth and land re-zoning will be focussed in. We have allowed for changes that are known and publicly available.	Zone changes will impact on demand growth. The implications of uncertainty for demand growth are noted above.	Low
Pricing	It has been assumed that the present pricing structures will be followed in the short term, which will evolve in the medium term to more cost reflective demand and capacity based pricing. This will promote demand side management, encourage distributed generation and reflect asset values/costs.	The assumption is based on the regulators and stakeholders encouraging efficient network development and for revenues to reflect cost drivers.	The present pricing structure does not promote demand side management and a move to capacity based pricing protects revenue against movements in energy demand such as greater uptakes of micro domestic generation and battery storage capacity.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Inflation Rate	It has been assumed that inflation will affect the annual forecast expenditure though the planning period. (All projections of expenditure are adjusted for inflation.)	The rate of inflation for cost increases has been based on projections sourced from financial institutions, which are based on CPI figures. In reality over time input costs (including those sourced from outside of New Zealand) for asset management activities will change at rates greater or less than the rate of general inflation. As expenditure forecasts are updated annually, this approach is acceptable and consistent with that prescribed.	Forward estimates are based on an inflation rate of 2% per annum. Higher inflation will mean higher costs in dollar terms. Lower inflation will give the reverse. (The inflation referred to is that associated with the renewal and construction of distribution networks, not general inflation).	Medium
Funding for Continued Growth	It has been assumed the cost of developing the network for growth and new customer connections will be financed by the additional income from the network customers plus contributions from customers for new connections. In the short term should growth levels remain at high levels, debt funding will be required for major investments in zone substations and other system growth projects.	The pricing structure is based on current company policy. Capital requirements for development of major zone substations and other system growth projects will exceed cash flows from normal business activities.	If growth does not go ahead, the expenditure for customer connections and growth as detailed in the long-term plan will reduce. Requirements for network development investment will likewise reduce with lower customer growth.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
Asset Renewals	We assume that asset renewals will be driven by issues such as condition based risk or asset health indices, rather than outright age. We expect assets in coastal areas to be renewed more frequently than those inland. We expect that increased focus on capital utilisation and consideration of depreciation, asset stranding and asset write downs will be part of our internal, and regulator driven investment process.	The projected Asset Replacement and Renewal programme is based upon the known condition and defect information gathered during annual asset inspections, together with estimated failure rates for assets of a specific age profile. We will improve our condition assessment processes and develop 'Health Index' processes to further refine our renewal investment projections.	Identification of specific asset issues may cause increased expenditure for certain asset classes within future years in which immediate replacement or removal from operation will incur costs.	Low
Major Customers	We assume all major customers, including NZ Steel (described separately below) continue at similar rates; that Drury South Business park will add 10 to 30MVA and Pokeno industrial area will add 20MVA to 25MVA of extra demand during the planning period; and that Envirowaste generation will remain at current levels.	Economic conditions are favourable, and we make our assumptions based on facts from customers and publicly available information.	Changes to major customer demands will have a material impact on our network demand forecasts, either higher or lower, which may change the timing of required investments. Decrease in demand will impact on revenue. Reductions in demand will affect network utilisation, may strand assets, and will have an impact on asset replacement decisions (retire rather than replace). A higher portion of transmission costs will be borne by us in this situation.	High

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
NZ Steel	Our assumption is that NZ Steel, our largest customer, and major contributor to the local economy will remain operating at current levels at both the Glenbrook and Maioro sites.	Information received from NZ Steel, and publicly available information, indicates that they will continue operating at current levels in the short to medium term.	Business conditions could worsen as a result of foreign exchange rates, demands for steel products changing and emissions controls (new Paris Agreement on climate change) leading to increased compliance and operating costs due to fuel substitution. A closure or downturn in production (or part of production such as iron sand mining at Maioro) would lead to decreased levels of direct consumption (affecting revenues), as well as lead to a regional economic decline affecting overall network demand and growth. A higher portion of transmission costs would have to be borne by Counties Power in this situation.	High
Transmission Pricing	We expect minor changes to the Transmission Pricing Methodology (TPM) which impacts on our transmission pricing but at this stage the exact impact is not known. We have at this time assumed that it will not have a material impact which would lead to a change of the current state. Assessment of RCPD demand using 100 peaks will put more importance on	Transpower has proposed regional transmission prices but consultation has not yet commenced. The EA has put on hold their proposed changes to the TPM guidelines. 100 RCPD peaks have been implemented already.	Significant changes to the TPM now seem less likely. But regional transmission price increases would result in customer prices having to increase to reflect any increased charges from Transpower.	Medium

Subject	Assumption	Basis for Assumption	Potential Impact of Uncertainty, if any	Level of Impact
	peak load management and demand side activities.			
Embedding or Bypass risk	We have assumed that there will be no embedded network created in our network area, nor any bypass of our network by third parties to supply key loads during the planning period	We have no current evidence that embedding is likely, as it is economically unattractive without appropriate scale. We continue to regularly liaise with our key customers and land developers to identify early embedded network opportunities.	Embedded networks could lead to reduced revenue and ICP growth over time, and potentially stranding of some existing network assets. However, these would still feature as demand on our network. Bypass of our network assets by a third party could lead to reduced revenue from lost supply opportunities and asset stranding and reduced growth in our demand forecasts.	Medium

Appendix B – Information Disclosure Schedule

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8			for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
9	**11a(i): Expenditure on Assets Forecast**			**$000 (in nominal dollars)**										
10		Consumer connection		11,000	12,690	13,362	12,485	12,734	12,989	13,249	13,514	13,784	14,060	14,341
11		System growth		9,372	26,420	26,112	22,015	21,521	12,827	309	9,460	8,730	17,165	12,429
12		Asset replacement and renewal		10,795	13,360	12,260	12,225	12,193	14,299	18,615	15,338	14,967	14,177	15,715
13		Asset relocations		500	300	306	312	318	325	331	338	345	351	359
14		Reliability, safety and environment:												
15		Quality of supply		-	350	357	364	371	379	-	-	-	-	-
16		Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment		1,000	1,195	394	364	371	8,075	386	394	402	410	418
18		**Total reliability, safety and environment**		1,000	1,545	751	728	743	8,454	386	394	402	410	418
19		**Expenditure on network assets**		32,667	54,315	52,791	47,765	47,510	48,893	32,891	39,044	38,228	46,163	43,262
20		Expenditure on non-network assets		2,710	6,433	2,626	2,163	1,450	1,499	1,509	1,540	1,590	1,602	1,634
21		**Expenditure on assets**		35,377	60,748	55,417	49,928	48,961	50,393	34,400	40,584	39,819	47,766	44,897
22														
23	*plus*	Cost of financing		86	143	139	121	118	119	78	91	87	103	95
24	*less*	Value of capital contributions		8,600	10,152	10,690	9,988	10,188	10,391	10,599	10,811	11,027	11,248	11,473
25	*plus*	Value of vested assets												
26														
27		**Capital expenditure forecast**		26,863	50,738	44,865	40,061	38,891	40,120	23,879	29,864	28,879	36,621	33,519
28														
29		Assets commissioned		26,863	50,738	45,318	40,061	38,891	40,120	23,879	29,864	28,879	36,621	33,519
30				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31			for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
32				**$000 (in constant prices)**										
33		Consumer connection		11,000	12,690	13,100	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
34		System growth		9,372	26,420	25,600	21,160	20,280	11,850	280	8,400	7,600	14,650	10,400
35		Asset replacement and renewal		10,795	13,360	12,020	11,750	11,490	13,210	16,860	13,620	13,030	12,100	13,150
36		Asset relocations		500	300	300	300	300	300	300	300	300	300	300
37		Reliability, safety and environment:												
38		Quality of supply		-	350	350	350	350	350	-	-	-	-	-
39		Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment		1,000	1,195	386	350	350	7,460	350	350	350	350	350
41		**Total reliability, safety and environment**		1,000	1,545	736	700	700	7,810	350	350	350	350	350
42		**Expenditure on network assets**		32,667	54,315	51,756	45,910	44,770	45,170	29,790	34,670	33,280	39,400	36,200
43		Expenditure on non-network assets		2,710	6,433	2,574	2,079	1,367	1,385	1,367	1,367	1,385	1,368	1,368
44		**Expenditure on assets**		35,377	60,748	54,330	47,989	46,137	46,555	31,157	36,037	34,665	40,768	37,568
45														
46	**Subcomponents of expenditure on assets (where known)**													
47		Energy efficiency and demand side management, reduction of energy losses												
48		Overhead to underground conversion		500	300	300	300	300	300	300	300	300	300	300
49		Research and development												

Company Name	Counties Power Limited
AMP Planning Period	1 April 2019 – 31 March 2029

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
50												
51												
52	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	-	262	485	734	989	1,249	1,514	1,784	2,060	2,341
55	System growth	-	-	512	855	1,241	977	29	1,060	1,130	2,515	2,029
56	Asset replacement and renewal	-	-	240	475	703	1,089	1,755	1,718	1,937	2,077	2,565
57	Asset relocations	-	-	6	12	18	25	31	38	45	51	59
58	Reliability, safety and environment:											
59	Quality of supply	-	-	7	14	21	29	-	-	-	-	-
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	8	14	21	615	36	44	52	60	68
62	**Total reliability, safety and environment**	-	-	15	28	43	644	36	44	52	60	68
63	**Expenditure on network assets**	-	-	1,035	1,855	2,740	3,723	3,101	4,374	4,948	6,763	7,062
64	Expenditure on non-network assets	-	-	51	84	84	114	142	172	206	235	267
65	**Expenditure on assets**	-	-	1,087	1,939	2,824	3,838	3,243	4,547	5,154	6,998	7,329
66												

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	$000 (in constant prices)					
70	Urban residential	5,500	6,345	6,550	6,000	6,000	6,000
71	Urban commercial	2,200	2,538	2,620	2,400	2,400	2,400
72	Rural residential	1,870	2,157	2,227	2,040	2,040	2,040
73	Rural commercial	1,430	1,650	1,703	1,560	1,560	1,560
74							
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	11,000	12,690	13,100	12,000	12,000	12,000
77	*less* Capital contributions funding consumer connection	8,600	10,152	10,480	9,600	9,600	9,600
78	**Consumer connection less capital contributions**	2,400	2,538	2,620	2,400	2,400	2,400
79	**11a(iii): System Growth**						
80	Subtransmission		320	5,500	6,100	4,100	
81	Zone substations		18,600	14,500	5,500	7,000	5,300
82	Distribution and LV lines		950	2,650	7,370	5,550	6,550
83	Distribution and LV cables		5,250	2,500	1,090	3,500	
84	Distribution substations and transformers		200	400	1,100	130	
85	Distribution switchgear			50			
86	Other network assets	9,372	1,100	-	-	-	-
87	**System growth expenditure**	9,372	26,420	25,600	21,160	20,280	11,850
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	9,372	26,420	25,600	21,160	20,280	11,850
90							

Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92			for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
93	**11a(iv): Asset Replacement and Renewal**			**$000 (in constant prices)**					
94			Subtransmission		50	50	50	50	50
95			Zone substations		650	50	350	350	350
96			Distribution and LV lines		7,170	6,680	8,240	7,910	9,350
97			Distribution and LV cables		330	340	350	360	510
98			Distribution substations and transformers		750	650	660	750	660
99			Distribution switchgear		2,320	1,740	1,400	1,380	1,570
100			Other network assets	10,795	2,090	2,510	700	690	720
101		**Asset replacement and renewal expenditure**		10,795	13,360	12,020	11,750	11,490	13,210
102		*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103		**Asset replacement and renewal less capital contributions**		10,795	13,360	12,020	11,750	11,490	13,210
104									

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106			for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
107	**11a(v):Asset Relocations**								
108			*Project or programme**	**$000 (in constant prices)**					
109			Others	500	300	300	300	300	300
110									
111									
112									
113									
114			**include additional rows if needed*						
115			All other project or programmes - asset relocations						
116		**Asset relocations expenditure**		500	300	300	300	300	300
117		*less*	Capital contributions funding asset relocations						
118		**Asset relocations less capital contributions**		500	300	300	300	300	300
119									

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121			for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
122	**11a(vi):Quality of Supply**								
123			*Project or programme**	**$000 (in constant prices)**					
124			Voltage quality resolution		350	350	350	350	350
125									
126									
127									
128									
129			**include additional rows if needed*						
130			All other projects or programmes - quality of supply						
131		**Quality of supply expenditure**		-	350	350	350	350	350
132		*less*	Capital contributions funding quality of supply						
133		**Quality of supply less capital contributions**		-	350	350	350	350	350
134									

Company Name	Counties Power Limited
AMP Planning Period	1 April 2019 – 31 March 2029

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

11a(vii): Legislative and Regulatory

for year ended	*Current Year CY* 31 Mar 19	*CY+1* 31 Mar 20	*CY+2* 31 Mar 21	*CY+3* 31 Mar 22	*CY+4* 31 Mar 23	*CY+5* 31 Mar 24
*Project or programme**	**$000 (in constant prices)**					
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environment

for year ended	*Current Year CY* 31 Mar 19	*CY+1* 31 Mar 20	*CY+2* 31 Mar 21	*CY+3* 31 Mar 22	*CY+4* 31 Mar 23	*CY+5* 31 Mar 24
*Project or programme**	**$000 (in constant prices)**					
Others	1,000	1,195	386	350	350	7,460
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	1,000	1,195	386	350	350	7,460
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	1,000	1,195	386	350	350	7,460

11a(ix): Non-Network Assets

for year ended	*Current Year CY* 31 Mar 19	*CY+1* 31 Mar 20	*CY+2* 31 Mar 21	*CY+3* 31 Mar 22	*CY+4* 31 Mar 23	*CY+5* 31 Mar 24
Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
IT	1,490	2,093	2,206	1,730	1,018	1,018
Vehicles, Other	345	215	368	349	349	368
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	1,835	2,308	2,574	2,079	1,367	1,385
Atypical expenditure						
*Project or programme**						
Office Upgrade	875	4,125				
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	875	4,125	-	-	-	-
Expenditure on non-network assets	2,710	6,433	2,574	2,079	1,367	1,385

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Company Name	**Counties Power Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7												
8	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,900	1,900	1,938	1,977	2,016	2,057	2,098	2,140	2,183	2,226	2,271
11	Vegetation management	1,100	1,350	1,377	1,405	1,433	1,461	1,491	1,520	1,551	1,582	1,613
12	Routine and corrective maintenance and inspection	1,350	1,350	1,377	1,415	1,443	1,472	1,502	1,532	1,574	1,605	1,637
13	Asset replacement and renewal	800	700	714	728	743	758	773	788	816	867	860
14	**Network Opex**	5,150	5,300	5,406	5,525	5,635	5,748	5,863	5,980	6,122	6,280	6,382
15	System operations and network support	3,717	4,084	4,166	4,249	4,334	4,421	4,509	4,599	4,691	4,785	4,881
16	Business support	5,896	6,179	6,344	6,514	6,689	6,869	7,054	7,244	7,440	7,641	7,847
17	**Non-network opex**	9,613	10,263	10,510	10,764	11,023	11,290	11,563	11,843	12,131	12,426	12,728
18	**Operational expenditure**	14,763	15,563	15,916	16,288	16,658	17,038	17,426	17,823	18,253	18,706	19,110
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	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
23	Vegetation management	1,100	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
24	Routine and corrective maintenance and inspection	1,350	1,350	1,350	1,360	1,360	1,360	1,360	1,360	1,370	1,370	1,370
25	Asset replacement and renewal	800	700	700	700	700	700	700	700	710	740	720
26	**Network Opex**	5,150	5,300	5,300	5,310	5,310	5,310	5,310	5,310	5,330	5,360	5,340
27	System operations and network support	3,717	4,084	4,084	4,084	4,084	4,084	4,084	4,084	4,084	4,084	4,084
28	Business support	5,896	6,179	6,220	6,261	6,303	6,346	6,389	6,433	6,477	6,521	6,566
29	**Non-network opex**	9,613	10,263	10,304	10,346	10,388	10,430	10,473	10,517	10,561	10,605	10,650
30	**Operational expenditure**	14,763	15,563	15,604	15,656	15,698	15,740	15,783	15,827	15,891	15,965	15,990
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	322	354	364	375	386	397	409	421	433	446	459
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	38	77	116	157	198	240	283	326	371
43	Vegetation management	-	-	27	55	83	111	141	170	201	232	263
44	Routine and corrective maintenance and inspection	-	-	27	55	83	112	142	172	204	235	267
45	Asset replacement and renewal	-	-	14	28	43	58	73	88	106	127	140
46	**Network Opex**	-	-	106	215	325	438	553	670	792	920	1,042
47	System operations and network support	-	-	82	165	250	337	425	515	607	701	797
48	Business support	-	-	124	253	386	523	665	812	963	1,119	1,281
49	**Non-network opex**	-	-	206	418	636	860	1,090	1,327	1,570	1,820	2,078
50	**Operational expenditure**	-	-	312	632	961	1,297	1,643	1,997	2,363	2,741	3,120

	Company Name	Counties Power Limited
	AMP Planning Period	1 April 2019 – 31 March 2029

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)						
7											
8											
9	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0.10%	3.83%	48.12%	47.89%	0.06%	3	3.95%
11	All	Overhead Line	Wood poles	No.	7.47%	5.91%	28.37%	58.20%	0.05%	3	9.90%
12	All	Overhead Line	Other pole types	No.	-	-	-	100.00%	-	3	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	4.77%	-	74.80%	20.43%	-	3	30.07%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	0.26%	99.74%	-	3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	22.64%	-	77.36%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	N/A	-
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.	16.67%	33.33%	50.00%	-	-	3	33.33%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.			33.33%	66.67%		3	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	8.33%	16.67%	25.00%	50.00%	-	3	33.33%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	58.62%	27.59%	13.79%	-	-	3	27.59%
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.	-	-	-	100.00%	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	22.50%	22.50%	15.00%	40.00%	-	3	26.25%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	N/A	-
35											

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		Company Name	Counties Power Limited
		AMP Planning Period	1 April 2019 – 31 March 2029

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

					Asset condition at start of planning period (percentage of units by grade)						
36											
37	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.		31.25%	31.25%	37.50%	-	3	25.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.16%	14.42%	48.62%	34.80%	-	3	6.10%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.13%	-	13.86%	86.01%	-	3	0.13%
44	HV	Distribution Cable	Distribution UG PILC	km	-	26.45%	46.29%	27.26%	-	3	55.88%
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.	-	6.79%	9.26%	83.95%	-	3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	13.21%	18.51%	40.16%	28.12%	-	3	6.55%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	5.61%	2.80%	15.89%	75.70%	-	3	9.35%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	7.50%	13.67%	36.79%	42.04%	-	3	7.50%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	3.49%	4.82%	33.37%	58.32%	-	3	3.49%
53	HV	Distribution Transformer	Voltage regulators	No.	-	14.29%	-	85.71%	-	3	14.29%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	10.17%	8.07%	35.44%	46.32%	-	3	10.17%
55	LV	LV Line	LV OH Conductor	km	0.64%	4.68%	64.78%	25.79%	4.11%	3	0.64%
56	LV	LV Cable	LV UG Cable	km	0.04%	1.36%	33.31%	65.28%	0.01%	3	0.04%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	0.51%	99.21%	0.28%	3	-
58	LV	Connections	OH/UG consumer service connections	No.	-	28.32%	39.36%	31.95%	0.37%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	20.14%	12.50%	1.39%	65.97%	-	3	22.22%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	11.27%	9.82%	15.27%	63.64%	-	3	16.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	79.31%	20.69%	-	3	-
62	All	Load Control	Centralised plant	Lot	40.00%	20.00%	20.00%	20.00%	-	2	20.00%
63	All	Load Control	Relays	No.	26.24%	6.91%	0.49%	66.36%	-	1	26.24%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

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Company Name	**Counties Power Limited**
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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
9	Pukekohe	37	60	n-1	8	62%	60	78%	No constraint within +5 years	
10	Opaheke	25	40	n-1	7	62%	40	111%	Transformer	Load to be transferred to Drury South substation in 2020/21
11	Tuakau	17	40	n-1	5	41%	40	132%	No constraint within +5 years	Load to be transferred to Pokeno substation in 2019/20
12	Ramarama	7	5	n-1	5	134%	40	41%	Transformer	Ramarama Substation will be decommissioned and replaced by Bombay area substation in 2021/22
13	Mangatawhiri	7	-	n	5	-	-	-	No constraint within +5 years	Mangatawhirir Substation will be decommissioned and replaced by Bombay area substation in 2021/22
14	Waiuku	17	15	n-1	5	116%	20	101%	Transformer	Waiuku 11kV Switchboard rating constraint. Switchboard proposed to be replaced as part of the Waiuku Zone substation redevelopment in 2019/20. Transformer short term ratings applied.
15	Karaka	12	20	n-1	2	59%	20	98%	No constraint within +5 years	
16	Maioro	10	9	n	3	-	-	-	No constraint within +5 years	Maioro Substation firm capacity is subject to commercial agreement with the major customer on site for new investment in the 5-year period.
17						-				
18						-				
19						-				
20						-				
21						-				
22						-				
23						-				
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Counties Power Limited**

AMP Planning Period: **1 April 2019 – 31 March 2029**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*				**Number of connections**		
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**						
12	Standard domestic	(280)	(310)	(317)	(324)	(331)	(338)
13	Low user domestic	1,350	974	993	1,012	1,032	1,052
14	Mass market business	(300)	130	132	134	136	138
15	Time of use business	9	10	10	10	10	10
	Distributed Streetlights	-	-	-	-	-	-
	Direct Charge	1	2	2	2	2	2
16							
17	**Connections total**	780	806	820	834	849	864
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	90	100	120	120	120	120
21	Capacity of distributed generation installed in year (MVA)	0.3	0.4	0.5	0.5	0.5	0.5
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
25	GXP demand	128	143	153	166	177	191
26	*plus* Distributed generation output at HV and above	6	6	6	6	6	6
27	**Maximum coincident system demand**	134	149	159	172	183	197
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	134	149	159	172	183	197
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	572	583	596	609	622	635
32	*less* Electricity exports to GXPs	-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation	44	46	45	45	45	45
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	616	629	641	654	667	680
36	*less* Total energy delivered to ICPs	588	600	612	624	636	649
37	**Losses**	28	29	29	30	31	31
38							
39	**Load factor**	52%	48%	46%	43%	42%	39%
40	**Loss ratio**	4.6%	4.6%	4.5%	4.6%	4.6%	4.6%

Company Name	**Counties Power Limited**
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SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	100.0	90.0	90.0	90.0	90.0	90.0
12	Class C (unplanned interruptions on the network)	150.0	110.0	110.0	110.0	110.0	110.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.40	0.40	0.40	0.40	0.40	0.40
15	Class C (unplanned interruptions on the network)	2.50	2.40	2.40	2.40	2.40	2.40

							Company Name	**Counties Power Limited**
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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?	2	The Asset Management Policy had previously been captured and detailed in the Asset Management Plan, with sections of the plan outlining the high level company policy. A standalone Policy was developed and approved by management in 2016, with alignment to the requirements of PAS 55 / ISO 55000 however its circulation and understanding by the wider organisation is limted to those directly involved in the management of network 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?	2	There is clear linkage between the organisation's vision and goals, approved policies, and the consideration of stakeholder needs (through service levels) when determining the asset strategy (through this AMP). Work is ongoing to develop individual lifecycle strategies for all assets, and to ensure all strategies meet the organisations objectives.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	Treatment of all parts of the asset lifecycle is set out in the AMP for major asset categories including planning, construction, operation, maintenance and disposal. Asset lifecycles are well understood for major asset categories but further development is required for all asset categories.		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	Currently, the AMP details lifecycle asset management plans for all major asset classes and maintenance and life-extension activities for the planning period. This is supported by working documents created by the Asset Management team. Lifecycle management plans take into account the long term optimisation of asset investments and trade-offs required. In the medium term, these will be better documented as standalone lifecycle management plans to be summarised in the AMP for disclosure purposes.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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			Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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 AMP is made available to all Asset Management staff, and those within the business who rely upon key information in it such as commercial, finance, field operations management and customer services. Major customers, territorial authorities and other utilities receive updates relating to plans in their areas, some within formally minuted account management meetings. Internal circulation is supplemented with briefings during monthly meetings; team meetings; and presentations of work programmes, key projects and other asset management initiatives.		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 team structure set out in the AMP, job descriptions, business plan responsibilities and personal performance plans establish responsibilities for delivery of AM actions.		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	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)	2	The AMP establishes financial estimates and resourcing arrangements for implementation. Plans may be adjusted for timing to ensure efficient utilisation of resources (e.g. bringing forward, or deferring programmes of work to match resource capacity within an acceptable risk profile). Medium and Long Term plans inform the organisation of future skills requirements and allow training or external contractors to be found to deliver on those requirements.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2	The AMP considers network and environmental risk, including disaster response and assessment of HILP events. Participation in CDEM and Engineering Lifelines activities ensures alignment with other infrastructure operators for regional events. Contingency plans for operation of the network assets are being developed. A review of emergency preparedness undertaken in 2017 indicates improvements to be made to major event management and business continutiy plans throughout 2018 and will continue to be developed in 2019		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	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	As outlined by the Asset Management Policy, the responsibility for AM activities sits with the GM Asset Management. The GM Field Operations has responsibility for delivery of the physical implementation of work programmes and projects relating to core network assets. Accountabilities are established through job descriptions and assigned activities. Appropriate delegations are in place.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	The development of the programmes of work presented in this AMP consider resourcing - financial, and phycial resources - required to deliver the expected outcomes in the timeframes required. When developing the annual plan, consideration is given to the type of work, the skills sets required, and outher resource constraints to ensure efficiencieny and sustainability in the long term. Consideration is given to outsourcing some activities where phycal resource capacity is not available. Significant effort has been made to resource the team to deliver on asset management objectives including an increase in engineering, field delivery and support functions within the business.		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	The significance of core asset management activities and meeting stated AM requirements is emphasised in newsletters, management communication, team meetings, company meetings, celebrations of particular programme successes, detailed reviews of issues and other asset related communications.		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	The organisation has an internal workforce so has limited outsourcing of asset management activities. Contractors have to meet the requirements of the "Preapproved Contractor Scheme" which covers safety, competence and commercial requirements. Work is supervised by internal resources where necessary, and the scope of work is typically very prescribed (e.g. civil works, tree felling, etc). Audits and contract reviews are used to ensure compliance and expected progress with corrective actions noted and addressed.		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	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?	2	The AMP is made available to all staff, and other stakholders via the website. Internal circulation is supplemented with briefings during monthly meetings; team meetings; and presentations of work programmes, key projects and other asset management initiatives. Beyond the AMP and programme specific information, some improvement is required in two way communication and feedback processes. Improvements are occuring in the provision of forecast information to service providers.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	Main systems and functions are detailed in the AMP. There is no clear documentation outlining the relationships between different systems and processes. This has been identified and will be addressed with the introduction of a new asset management information system (whole process mapping) which is expected to be completed during 2019		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	The asset management information systems have limited capability but support core business function. As per Q.59 a review of the asset management system and IT requirements, along with process and standards review is underway with key deliverables completed during 2019		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	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?	2	Asset information is primarily maintained within the company ERP. This provides access controls and auditing. GIS is used to provide the geographic context of assets and also to a lesser degree to record some asset information. An initiative is underway to review and improve asset data quality in this system, which may lead to specific programmes to update and improve quality. A variety of other disparate databases and spreadsheets are in the process of being incorporated within the ERP (or its replacement).		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	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The AMP outlines the core business systems relating to asset management. Following review it has been identified that the systems are no longer providing the required functionality and a project has been included for the replacement of the ERP system and improvement of the asset management system (implementation of a CMMS)		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	The corporate risk framework and audit programme identifies a number of risks relating to asset management activities with corresponding controls in place. These are assessed preiodically for effectivness. Asset specific risk is addressed through the planning process and maintenance programmes in place and detailed in the AMP. Some of these are still in development and are not yet fully documented, or documentation is out dated.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Actions arising from risk assessments relating to training, competency development and resourcing are captured in traingng and development plans, as well as updating job specific competencies and position descriptions.		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	The business has established a compliance framework, and through active monitoring of the regulatory environment, along with particpation in industry bodies such as the EEA and ENA identifies ongoing requirements, and new or ammended requirements. Practices and processes are updated as required to ensure ongoig compliance. Senior Management team members report on compliance issues periodically.		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	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	Procedures for planning, design and construction exist in varying forms, with some not as current as others. A major project to review the standards framework (including polices and procedures) will continue during 2018.		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	2	Procedures for maintenance and inspection of assets exist in varying forms, with some not as current as others. A major project to review the standards framework (including polices and procedures) will be continue during 2018.		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?	2	The routine inspection process captures information relating to defects and hazards, but not a specific, objective assessment of asset condition. Mobile technology is used for inspection records and the quality of information for decision making has improved. As part of the maintenance standards review, a more specific condition assessment regime will be introduced.		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?	2	An incident reporting process in place, and asset-related failures, worksite incidents and emergency situations all initiate processes for investigation and mitigation. Outcomes of audits and investigations are available to all staff. The Intranet is used as a common internal communication system. Non-conformances with processes and procedures are routinely reported, with an emphasis on health and safety impacts. More formal processes relating to asset failure and network performance investigations are being developed.		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	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Procedures for audit exist in some aspects of the AM systems and processes, such as safety, quality and financial. Some areas of process and systems do not yet have established audit procedures and these are developed on a case by case basis to address identified issues or risks.		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?	2	Results of inspections and investigations of failures are reviewed by subject experts and used as inputs into the AM programme. Follow-through is recorded in action plans, minutes and the contents of related documentation.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	Exploration of improvement is evident in action; in the execution of innovative projects and process improvements; and in recognition within the industry. Specific initiatives are recorded in the business plan for development; with opportunity registers regularly reviewed by senior management.		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	Participation in industry forums ; conferences; joint initiatives; participation in relevant industry groups; international data gathering and research and inclusion of appropriate goals in personal development and business plans. Business case assessment for new technologies and operating arrangements/partnerships is actively undertaken.		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.

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. 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)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The difference between nominal and constant prices reflects inflation of 2% per annum

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
The difference between nominal and constant prices reflects inflation of 2% per annum

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Appendix C – Assessment against Information Disclosure Requirements

Information Disclosure Requirements 2015 clause	AMP Section
3 The AMP must include the following -	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	Plan Summary
3.2 Details of the background and objectives of the EDB's asset management and planning processes	4
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	1.1
3.3.2 states the corporate mission or vision as it relates to asset management	1.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	1.1
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	1.1
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	1.1
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	1.2
3.5 The date that it was approved by the directors	1.3
3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	2.4
3.6.1 how the interests of stakeholders are identified	2.4
3.6.2 what these interests are	2.4
3.6.3 how these interests are accommodated in asset management practices; and	2.4
3.6.4 how conflicting interests are managed	2.4
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	2.1.3; 2.1.4
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	2.1.3

Information Disclosure Requirements 2015 clause	AMP Section
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured and	2.1.3
3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	2.1.3;2.1.4
3.8 All significant assumptions	Appendix A
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; and	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.	On forecasts; Appendix A
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	Appendix A
3.10 An overview of asset management strategy and delivery	4.1; 4.2; 4.4
3.11 An overview of systems and information management data	4.3
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	4.3.2
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance	4.4.1
3.13.2 planning and implementing network development projects	4.4.1
3.13.3 measuring network performance.	4.3.2
3.14 An overview of asset management documentation, controls and review processes	4.3.2
3.15 An overview of communication and participation processes	4.3.2
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	Throughout AMP

Information Disclosure Requirements 2015 clause	AMP Section
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Throughout AMP
Assets covered	
4 The AMP must provide details of the assets covered, including-	
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	2.1
4.1.1 the region(s) covered	2.1; Appendix E
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities	2.5.1
4.1.3 description of the load characteristics for different parts of the network	2.5.3
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.7
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;	2.5.2; 2.6
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;	2.6; 6.4
4.2.3 a description of the distribution system, including the extent to which it is underground;	2.6
4.2.4 a brief description of the network's distribution substation arrangements;	2.6
4.2.5 a description of the low voltage network including the extent to which it is underground; and	2.6
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	5.8
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 must be disclosed for each sub-network.	N/A
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category-	

4.4.1 voltage levels;	2.6.1; 2.6.2
Information Disclosure Requirements 2015 clause	**AMP Section**
4.4.2 description and quantity of assets; 4.4.3 age profiles; and	5.1 - 5.10 5.1-5.10
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.	5.1-5.10
4.5 The asset categories discussed in subclause 4.4 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	5.1-5.10 5.1-5.10 5.1 5.9
4.5.4 Other generation owned by the EDB.	N/A
Service levels	
5 The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period. 6 Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years. 7 Performance indicators for which targets have been defined in clause 5 above should also include- 7.1 Consumer oriented indicators that preferably differentiate between different consumer types; 7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	3.2-3.6 3.4 3.4 3.6
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	3

or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	
9 Targets should be compared to historic values where available to provide context and scale to the reader.	3
Information Disclosure Requirements 2015 clause	**AMP Section**
10 Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	3
Network Development Planning	
11 AMPs must provide a detailed description of network development plans, including— 11.1 A description of the planning criteria and assumptions for network development;	 6.1
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated, and the methodology briefly described;	6.1
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	6.1.3; 6.1.4
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss- 11.4.1 the categories of assets and designs that are standardised; 11.4.2 the approach used to identify standard designs.	 6.1.3 6.1.3
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	4
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.	6.1.3
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.	6.1; 4
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;	6 6.2

11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	6.4; 6.5
Information Disclosure Requirements 2015 clause	**AMP Section**
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	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.	Appendix A
11.9 Analysis of the significant network level development options identified, and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;	6.4; 6.5 6.4; 6.5 6.4; 6.5
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	6.1.4; 6.1.5; 6.4; 6.5
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;	6.4-6.6 6.4-6.6
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.	6.4-6.6 6.4-6.6
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.	6.2; Appendix A
11.12 A description of the EDB's policies on non-network solutions, including-	4.2.3

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	6.1.5
11.12.2 the potential for non-network solutions to address network problems or constraints.	6.1.5
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12 The AMP must provide a detailed description of the lifecycle asset management processes, including—	
Information Disclosure Requirements 2015 clause	**AMP Section**
12.1 The key drivers for maintenance planning and assumptions;	4.1
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-	5.2-5.8
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;	5.2-5.10
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	5.2-5.10
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	8.1.1; 8.2.1
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-	4;5
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;	4
12.3.2 a description of innovations that have deferred asset replacements;	4.1.3; 4.2
12.3.3 a description of the projects currently underway or planned for the next 12 months;	5.2-5.8
12.3.4 a summary of the projects planned for the following four years (where known); and	5.2-5.8
12.3.5 an overview of other work being considered for the remainder of the AMP planning period.	5.2-5.8
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in subclause 4.5.	5.2-5.8
Non-Network Development, Maintenance and Renewal	
13 AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	7
13.1 a description of non-network assets;	7

13.2 development, maintenance and renewal policies that cover them;	7
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	7
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	7
Risk Management	
14 AMPs must provide details of risk policies, assessment, and mitigation, including—	
14.1 Methods, details and conclusions of risk analysis;	4.5
Information Disclosure Requirements 2015 clause	**AMP Section**
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;	4.5-4.8
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2;	4..5-4.8
14.4 Details of emergency response and contingency plans.	4.8
Evaluation of performance	
15 AMPs must provide details of performance measurement, evaluation, and improvement, including—	9
15.1 A review of progress against plan, both physical and financial;	9
15.2 An evaluation and comparison of actual service level performance against targeted performance;	3.2-3.6
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.	Schedule 13 attached to AMP
15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	3.2-3.6; 4.10
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;	Throughout AMP
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1

Appendix D – Director Certification

Schedule 17 Certification for Year-beginning Disclosures
Clause 2.9.1 of section 2.9

We, Douglas John Troon and Vernon John Dark, being directors of Counties Power Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

1. The following attached information of Counties Power Limited prepared for the purposes of clauses 2.4.1, 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.

2. The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

3. The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Counties Power's corporate vision and strategy which are documented in retained records.

DJ Troon (Director)

VJ Dark (Director)

Certified at Pukekohe this 20th day of March 2019

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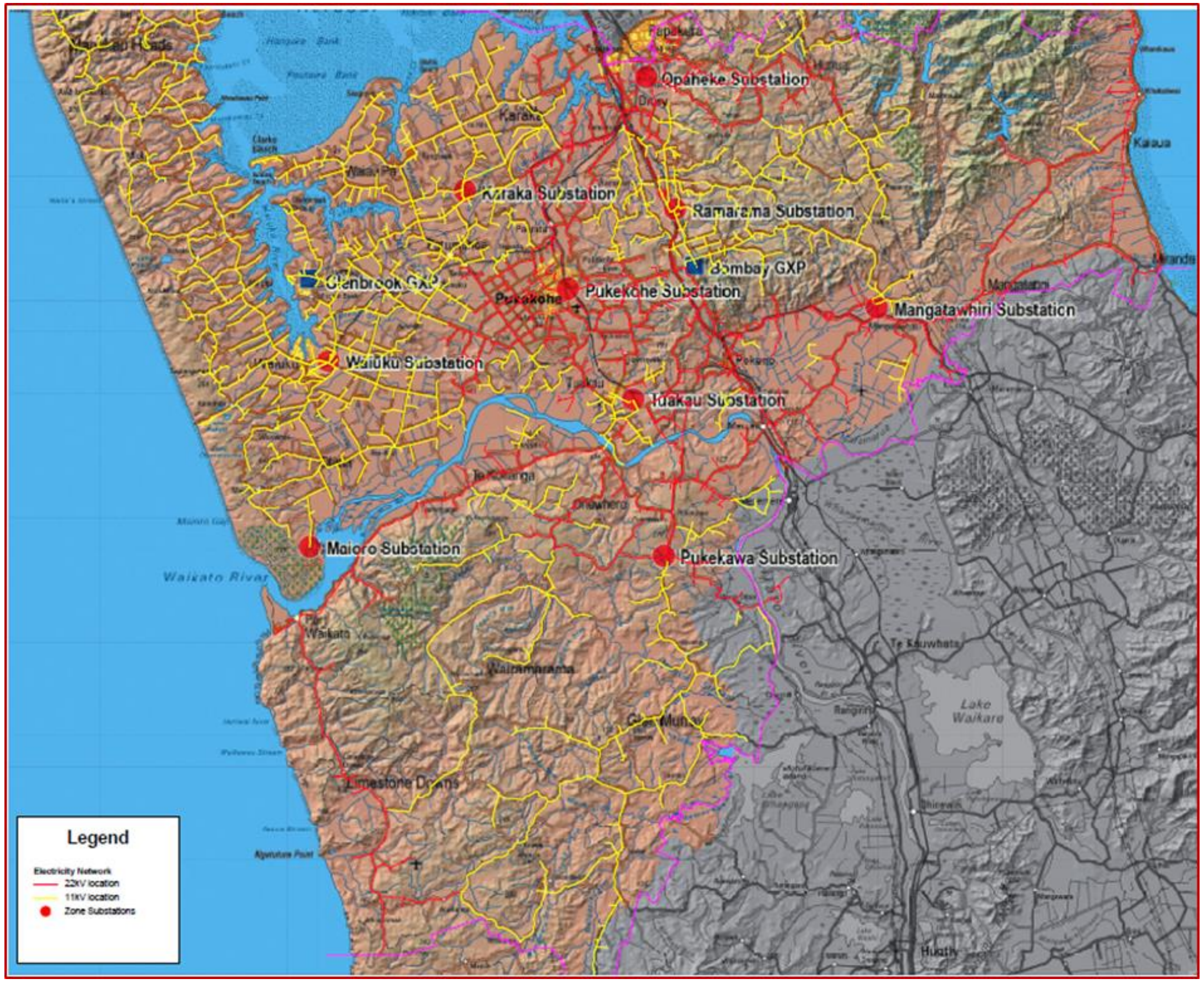
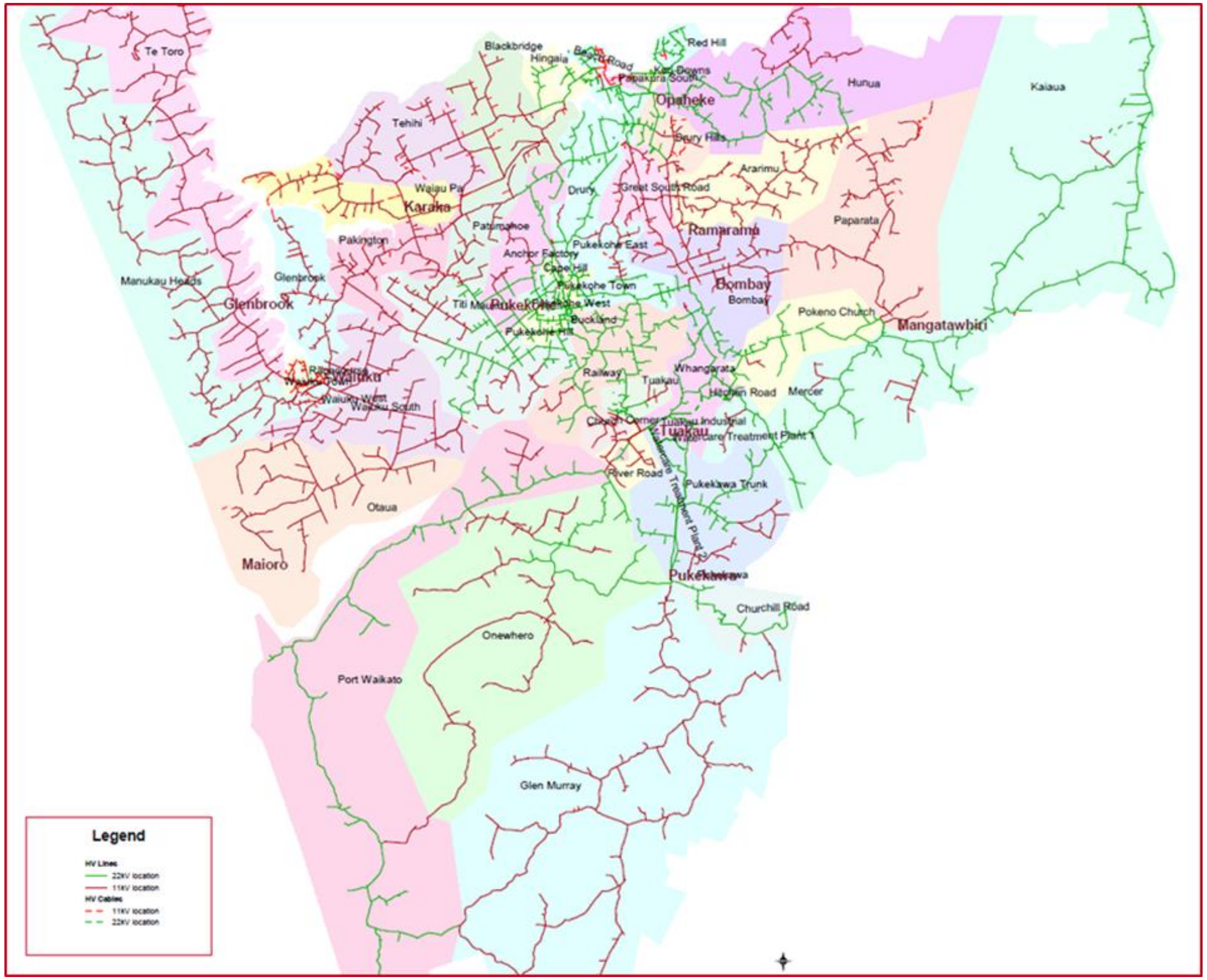
Appendix E – Network overview diagrams



Overview of network feeders with operating voltages figure



Overview of network feeder coverage areas

Appendix F – Glossary

Term	Description
AAC	All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABS	Air Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ALARP	As Low As Reasonably Practicable
AMMAT	Asset management maturity assessment tool
AMP	Asset Management Plan
Ampere (A)	Unit of electrical current flow, or rate of flow of electrons.
Bus	(Busbar) A common connection point between multiple circuits and equipment.
Bushing	An electrical component that insulates a high voltage conductor passing through a metal enclosure.
Buchholz protection	A Buchholz relay is a safety device sensing the accumulation of gas in large oil-filled transformers, which will alarm on slow accumulation of gas or shut down the transformer if gas is produced rapidly in the transformer oil.
CAIDI	Customer Average Interruption Duration Index is the average total duration of interruption per interrupted customer.
Capacity	The greatest amount of load a circuit can carry.
CB	Circuit Breaker
CBD	Central Business District
Conductor	'Wire' that carries the electricity and includes overhead lines which can be covered (insulated) or bare (not insulated) and underground cables which are insulated.
CT	Current Transformer
Demand	The amount or energy sought by the consumers.
DCIU	Data Concentrator Interface Unit used in SCADA
DNP3	Distributed Network Protocol: A set of communications protocols used between components in SCADA
DO	Drop-out Fuse Switch or Disconnector/Isolator
Disconnector	Also known as a disconnecting switch, isolator, or drop-out
Distribution Line	[Ref NZECP 34] Means works that are owned by Counties Power used for the conveyance of electricity to one or more electrical installations.
Distribution Pillar	A plastic ground mounted enclosure, usually found on a properties boundary containing the fuses for a service supply.
Easement	An easement is a right given to another person or entity to trespass upon land that person or entity does not own
Earth-fault	A circuit conductor unintentionally grounded.
EDB	Electricity Distribution Business
EEA	Electricity Engineers' Association (EEA)
EIPC	Electricity Industry Participation Code 2010 (the "Code")
FY	Financial Year e.g. FY2013 is Financial Year 2014 which covers 1st April 2013 to 31st March 2014
Fault	means a physical condition that causes a device, component or network element to fail to perform in the required manner
Feeder	A physical grouping of conductors that originate from a district/zone substation circuit breaker.
Fixed Asset	A purchase normally over $500 with an intended life cycle of at least over one year.
Flashover	A disruptive discharge around or over the surface of an insulator.
GIS	The Geographic Information System used for electronic mapping of the network.
Grid Exit Point (GXP)	The point at which Counties Power Equipment is deemed to connect to the Transpower Grid System.
GWh	giga-watt hour

Term	Description
Harmonic distortion	Distortion of the sine wave which represents ideal AC power. Usually by super imposed higher frequencies.
High Voltage (HV)	Any voltage exceeding 1000 V a.c. or 1500 V d.c. but usually pertaining to the 11kV or 33kV distribution system.
ICP (Installation Control Point)	A number that uniquely identifies each connection to an electrical lines network that is recorded in a national registry.
Kiosk	A small structure, often open on one or more sides.
kV	kilo-volt
Lines	The LV and HV network of overhead and underground electricity conductors and cables and their associated equipment such as insulators, poles, crossarms etc.
Load Break Switch	A switch that can be operated under load.
Injection Plant	Injects a signal onto 50Hz network, for controlling ripple relays.
Low Voltage (LV)	Any voltage exceeding 32 V a.c. or 115 V d.c. but not exceeding 1000 V a.c. or 1500 V d.c.
MV circuit breakers	Medium voltage circuit breaker
MW	mega-watt
Maximum Demand	The highest value of the power or apparent power taken within the account period, such as, month or year.
MVA	mega-volt-ampere
n-1 security	A load is said to have n-1 security if for the loss of any one item of equipment supply to that load is not interrupted or can be restored in the time taken to switch to alternate supplies. Network Utility reticulation system or asset owned by the utility Company, Trust or other body having control and/or ownership in the utility reticulation system including the land, buildings, installations, individual customer connections up to the point of supply, and other improvements on or under which the utility reticulation system is located.
NAV	ERP and accounting software package; version used in Counties Power is Microsoft Dynamics NAV R2 2009
NZECP35	New Zealand Electrical Code of Practice for Power System Earthing
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
ONAN	Abbreviation denote the cooling method used for a transformer: Oil natural, Air natural –no fans or pumps are running, cooling uses natural convection through radiators
ONAF	Abbreviation denote the cooling method used for a transformer: Oil Natural, Air Forced - no oil pump running, fans running forcing air across radiators
OFAF	Abbreviation denote the cooling method used for a transformer: Oil forced (pumped), Air Forced (Fans)
Outage	an interruption to electricity supply
Overcurrent	Current in excess of the rated current of a conductor.
Overhead	Above ground, pole mounted conductor
PSMS	Public Safety Management System
QMS	Quality Management System
RAB	Residual asset base
Recloser	A piece of equipment on the distribution network work which automatically trips when a fault is detected (typically a tree touching the line) and recloses after a set time (minutes).
Reliability	The ability of an item to perform a required function under stated conditions for a stated period of time.
Remaining economic life	The likely future period during which an Asset is expected to generate a positive contribution to value.
Residual Risk	The remaining level of risk after risk treatment measures has been taken.
Retailer	An electrical energy supplier who has a User Supply Agreement with Counties Power.
Risk	Probability (likelihood) and consequences, positive or negative, of an event. In some situations, risk is a deviation from the expected.

Term	Description
Risk Management	AS/NZS 4360 defines risk management as a term applied to a logical and systematic method of identifying, analysing, evaluating, treating, monitoring and communicating risk associated with any activity, function or process in a way that enables maximisation of benefits or minimisation of losses or detrimental effects.
RMU	Ring Main Unit
RTU	Remote Terminal Unit – Communications device used for relaying data from the field.
SAIDI	System Average Interruption Duration Index is the average total duration of interruption per connected customer.
SAIFI	System Average Interruption Frequency Index is the average number of interruptions per connected customers.
SCADA	Counties Power's computerised System Control And Data Acquisition System being the primary tool for monitoring and controlling access, and switching operations for Counties Power's Network
Smallworld	GIS-based system for mapping of the network
Stakeholder	People and organisations who may affect, be affected by, or perceive themselves to be affected by a decision or activity.
Standard	The document that prescribes the requirements with which the product or service must conform. The criteria for acceptable levels of safety performance/behaviours set by Counties Power, industry codes or relevant legislation.
Standard Operating Procedure (SOP)	A locally controlled work method statement or 'desk top' file.
Substation	Electrical facility where the voltage of incoming and outgoing circuits is changed and controlled.
Supplier	Organisation that provides a service or product to the customer:
Test Permit	The permit for access to HV equipment which has been removed from service to enable testing and where procedures are required to control hazards created by the testing.
Transpower	The national grid operator.
UHF	Ultra High Frequency.
User	Any person or organisation using the Distribution System but excluding Transpower. It includes all Customers, embedded generators, and where appropriate, Electricity Retailers acting on behalf of their customers.
Vegetation	Any trees or other plants threatening the Counties Power Networks overhead lines.
VHF	Very High Frequency
Voltage regulators	A voltage regulator is an electrical regulator designed to automatically maintain a constant voltage level.
VT	Voltage Transformer
WIP	Work in Progress
WWTP	Waikato Water Treatment Plant
XLPE	Type of cable insulation – Cross-linked Polyethylene
Zone Substation	Includes HV substations, switching stations, voltage regulators, ground mounted HV switchgear, large industrial/commercial distribution substations, ripple control plant, and associated protection and controls.